Programme Area: Carbon Capture and Storage

Project: Aquifer Brine

Title: Brine production cost-benefit analysis tool documentation and draft CBA results

Abstract:

This is the report that accompanies the 'Brine Production Cost Benefit Analysis' tool. This report covers the cost benefit analysis of the brine aquifer management for CO2 storage, it analyses any benefits of producing brine to manage pressure in aquifers used to store CO2. The CBA tool kit report provides a brief description on background details of the excel model that has been produced. It contains a user manual for the tool in Appendix 8. It provides simple cost metrics for the storage of CO2 from CO2Stored and demonstrated how these costs can be affected by the extraction of brine to manage the store.

Context:

This £200,000 nine-month long project, studied the impact of removing brine from undersea stores that could, in future, be used to store captured carbon dioxide. It was carried out by Heriot-Watt University, a founder member of the Scottish Carbon Capture & Storage (SCCS) research partnership, and Element Energy. T2 Petroleum Technology and Durham University also participated in the project. It built on earlier CCS research work and helped develop understanding of potential CO2 stores, such as depleted oil and gas reservoirs or saline aquifers, located beneath UK waters. It also helped to build confidence among future operators and investors for their operation. Reducing costs and minimising risks is crucial if CCS is to play a long-term role in decarbonising the UK's future energy system.

Brine production cost-benefit analysis tool documentation and draft CBA results

Updated final report

(Model V042)

for

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Disclaimer

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1 Background

Element Energy previously led the economic analysis within the UK Storage Appraisal Project, and the outputs from this currently feature in CO_2Stored. In the UKSAP, Element developed a methodology to allow infrastructure to be sized and capital and operating costs to be estimated for a wide range of conditions ensuring the rapid screening of 574 storage units.

Following the UKSAP, Element Energy developed "CO_2NomicA", the ETI's economic network analysis tool, and used this to examine more than 100 configurations for offshore transport and storage infrastructure.

In this study, a cost-benefit analysis tool has been built to examine the impact of the additional brine wells required and the changes in pressure, injectivity and storage capacity on storage economics (e.g. cost of transmission and distribution pipelines, injection facilities, wells, etc.) under a number of scenarios and sensitivities.

Cost datasets and methodology for transport and storage economics developed by Element Energy during UKSAP and CO_2NomicA have been used and updated as necessary with the engineering and cost requirements for brine production. Some of the previous cost datasets have been updated based on a review of the detailed transport and storage costs developed by the Strategic UK CCS Storage Appraisal Project.

The figure below shows the key steps that were taken to develop a brine production infrastructure cost model and carry out a cost-benefit analysis for brine production.

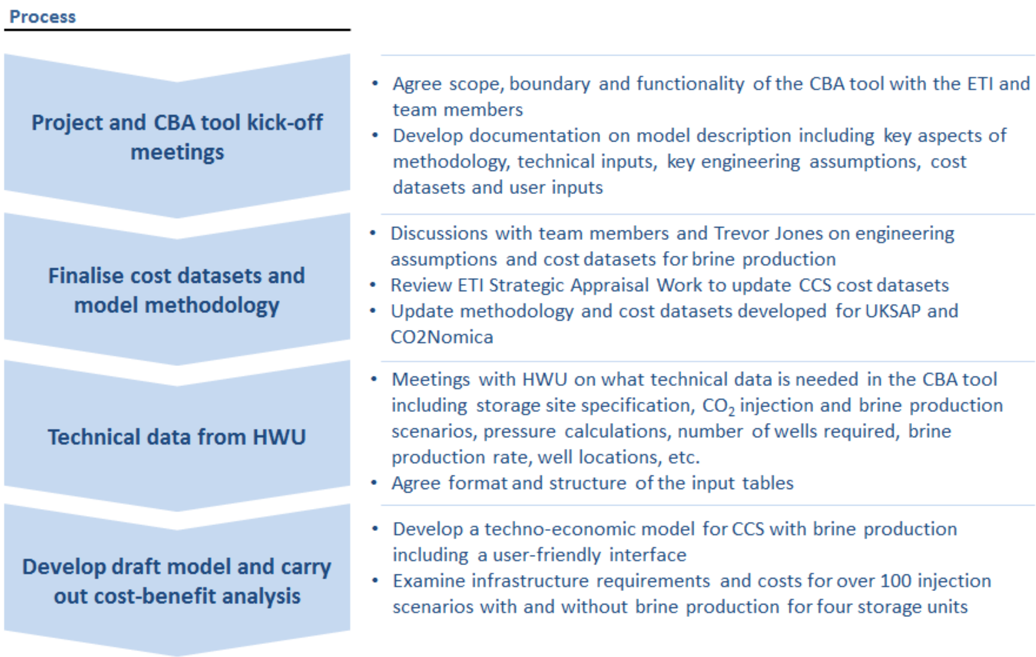


Figure 1: Project background diagram

It is suggested that potential users have the following skills:

- Understanding of the CO_2 transport and storage infrastructure;
- Previous experience in carrying out techno-economic analysis or using similar models;

- Understanding of the technical and economic uncertainties associated with CCS; and
- Familiarity with the UKSAP and CO_2Stored database.

This document describes the Brine Production CBA Tool including:

- Key aspects of model methodology;
- Key inputs of the model;
- Key engineering assumptions and cost datasets;
- Limitations, future work recommendations and Arising IP
- Model user interface; and
- Draft CBA results.

2 Key aspects of model methodology

The figure below illustrated the boundary of the cost-benefit analysis tool. The following infrastructure is included in the analysis:

- Through onshore pipelines, power plants or industrial sites are connected to a shoreline boosting hub; where it is assumed that the CO_2 is delivered at 10 MPa at the required purity for offshore pipeline transport and geological storage and compressed to 25 MPa. CO_2 capture and onshore pipelines are not included in the tool.
- CO_2 is then transported from shoreline terminals to storage sites through offshore pipelines with certain diameters depending on limiting pressure drops.
- Where offshore boosting is required, hubs are added to the network and distribution pipelines are used for CO_2 transport from hub to CO_2 injection facilities, which are either sub-sea facilities or platforms.
- CO_2 is injected to the sink through CO_2 injection wells – the number of injection wells needed, which have been calculated by the Heriot-Watt University, depends on CO_2 flow rates and pressure limits associated with injection.
- The CBA tool also includes costs for well remediation (as existing wells drilled primarily for hydrocarbon production could provide a pathway for CO_2 to escape from a designated storage site) and appraisal (i.e. cost of seismic assessment and appraisal wells for each sink).
- In addition to the typical CCS infrastructure, the CBA tool includes brine production wells and water treatment facilities depending on the level of brine production needed and whether oil separation is needed.

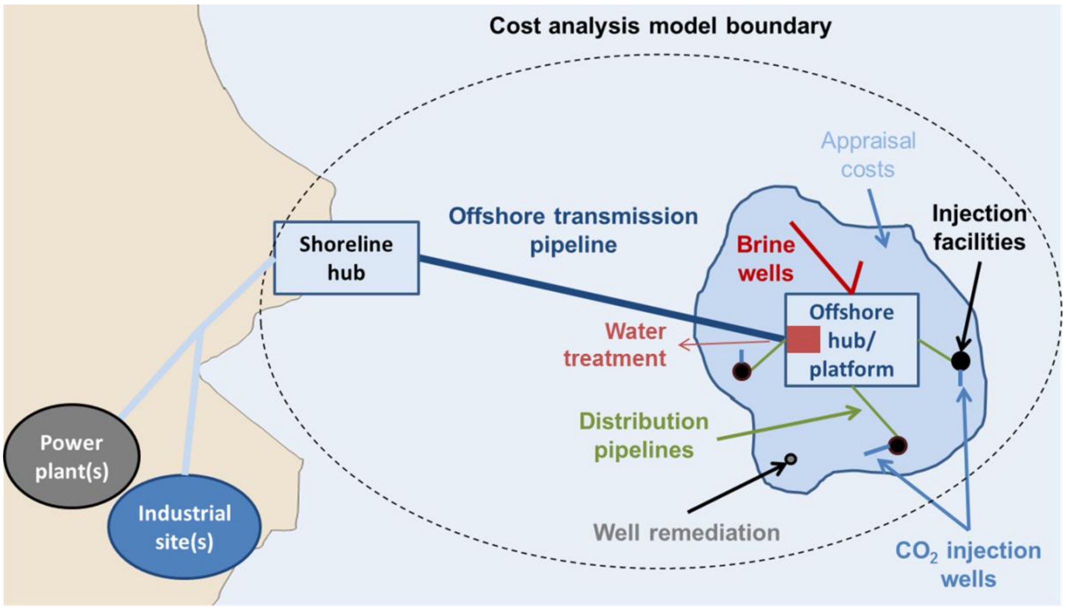


Figure 2: Boundary of the CBA tool

The figures below show the high-level model methodology for calculation transport and storage costs with and without brine production – including key technical inputs, key cost datasets and scenario inputs.

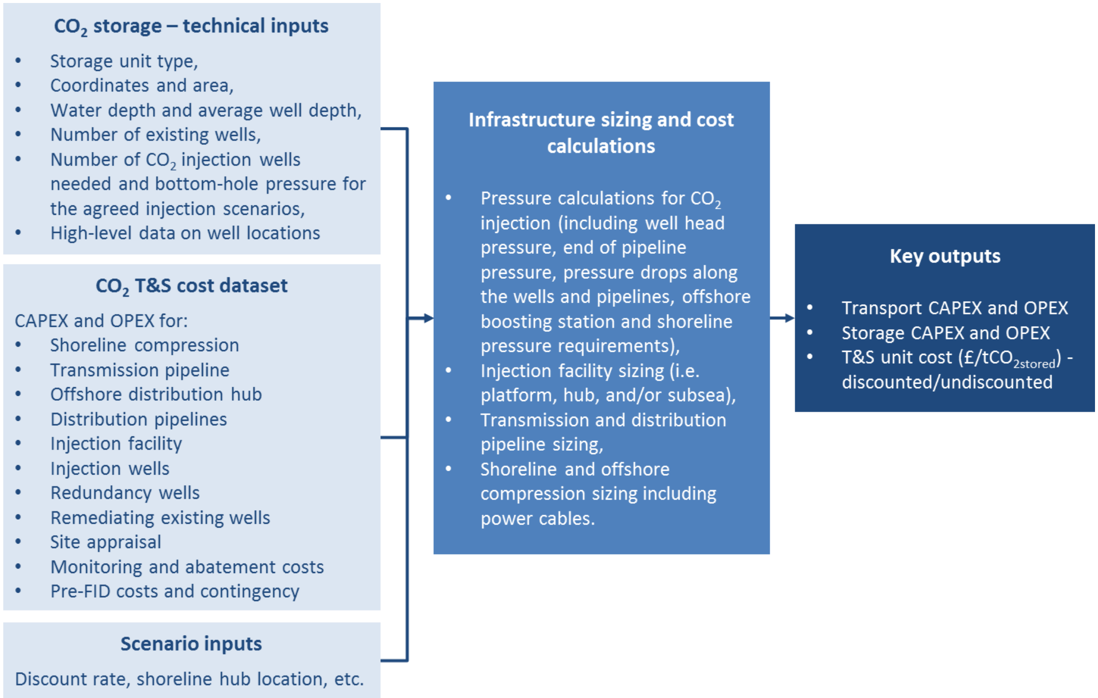


Figure 3: Calculation of key outputs without brine production

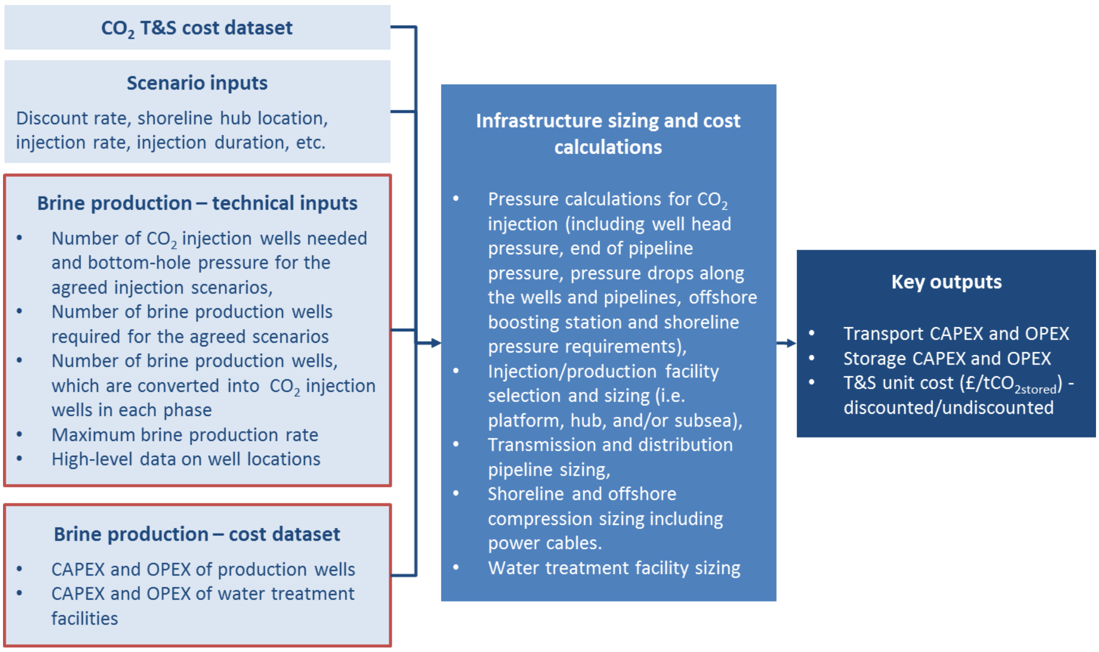


Figure 4: Calculation of key outputs with brine production

3 Key inputs of the model

3.1 Technical inputs

Key technical inputs are listed below for storage site specifications and well requirements, which have been provided by the Heriot-Watt University.

Table 1: Key technical inputs

Storage site specifications	Well requirements
• Site description • Sink type • Risk score • Latitude • Longitude • Area (m^2) • Water depth (m) • Depth to storage (m) • Existing number of wells	• Flow rate (Mt/year) • Injection duration (years) • Brine production (Yes/No) • Well type (Vertical/Horizontal) • Well conversion status (Yes/No – i.e. whether brine production wells are converted into CO_2 injection wells) • Total number of total CO_2 injection wells • Total number of CO_2 injection wells converted from brine production wells • Total number of brine production wells • Bottom-hole pressure (MPa) • Grid length (m) • Grid width (m) • Average well depth (m) • Maximum brine production (m^3/day)

Grid length and width (which are illustrated below) are used to identify the likely locations of CO_2 injection and brine production wells, which are used for the configuration of CO_2 injection facilities.

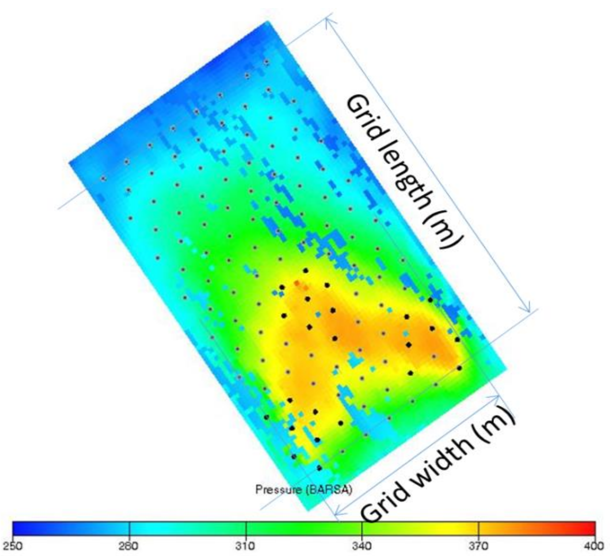


Figure 5: Grid length and width

3.2 Scenario inputs

The tool can be used to run all injection scenarios under a defined scenario. Alternatively, a specific scenario can be defined a selected storage site to explore costs and benefits in more detail. The user interface is explained in more detail in Section **Error! Reference source not found.**.

Scenario definition for all injection scenarios

The tool requires the following scenario inputs:

- Shoreline terminal selection:
  - Tool selects nearest terminal or user selects a terminal
- If user would like to select a terminal:
  - Bacton (1.46, 52.86)
  - Barrow (-3.18, 54.09)
  - Easington Shore (0.12, 53.65)
  - Forth (-3.69, 56.01)
  - Humber (0.23, 53.36)
  - Milford Haven (-5.08, 51.7)
  - St Fergus (-1.84, 57.58)
  - Teesside (-1.19, 54.61)
  - Thames (0.69, 51.44)
  - Wirral (-3.32, 53.34)
- Discount rate
- Sensitivity inputs:
  - Oil separation required for all sites (Yes/No)
  - Injection well redundancy (Default is 10% of total number of injection wells)
  - Brine production well redundancy (Default is 0%)
  - Remediation of existing wells (Default is 0% of existing well)
  - Maximum injection facility coverage radius (Default is 5,000m)
  - Whether subsea brine production is possible (Yes/No)

Scenario definition for a selected storage site

If the user would like to use the tool to examine a selected storage unit in more detail, the following inputs are required:

- Storage site
- Flow rate (2, 5, 10, 15, 20, 40, or 60 Mt CO_2/y)
- Injection duration (10, 20, 30 or 40 years)
- Brine production status (Yes/No)
- Well type (Vertical/Horizontal)
- Well conversion status (Yes/No)
- Sensitivity inputs:
  - Number of CO_2 injection wells
  - Number of converted CO_2 injection wells
  - Brine production wells (including redundancy)
  - Bottom hole pressure (MPa)
  - Grid length (m)
  - Grid width (m)
  - Average well depth (m)
  - Maximum brine production (m3/d)

These are explained in the “Model user manual” section.

4 Draft CBA results

Technical data provided

A detailed CBA analysis has been carried out for four Saline Aquifers including Forties 5, Bunter, Tay and Firth of Forth using the brine production scenarios listed below, which were provided by the Heriot-Watt University. For each scenario, detailed data on "Number of CO_2 injection wells, "Converted number of CO_2 injection wells", "Number of brine production wells", "Bottom hole pressure (MPa)", "Grid length (m)", "Grid width (m)", "Average well depth (m)", and "Maximum brine production rate (m^3/d)" were provided for 28 injection scenarios (2, 5, 10, 15, 20, 40 and 60 $MtCO_2$ injection per year; and injection durations of 10, 20, 30 and 40 years). Technical inputs were explained in Section 3.1.

- **Forties 5 – Scenario 1:**
  - Vertical wells
  - Without brine production and no well conversion
- **Forties 5 – Scenario 2:**
  - Horizontal wells
  - Without brine production and no well conversion
- **Forties 5 – Scenario 3:**
  - Vertical wells
  - With brine production and no well conversion
- **Forties 5 – Scenario 4:**
  - Horizontal wells
  - With brine production and no well conversion
- **Forties 5 – Scenario 5:**
  - Horizontal wells
  - With brine production and with well conversion (i.e. some of the brine production wells are converted into CO_2 injection wells over time)
- **Bunter – Scenario 1:**
  - Vertical wells
  - Without brine production and no well conversion
- **Bunter – Scenario 2:**
  - Vertical wells
  - With brine production and with well conversion (i.e. some of the brine production wells are converted into CO_2 injection wells over time)
- **Tay – Scenario 1:**
  - Vertical wells
  - Without brine production and no well conversion
- **Tay – Scenario 2:**
  - Vertical wells
  - With brine production and no well conversion
- **Firth of Forth – Scenario 1:**
  - Vertical wells
  - Without brine production and no well conversion
- **Firth of Forth – Scenario 2:**
  - Vertical wells
  - With brine production and no well conversion

CBA results for Forties

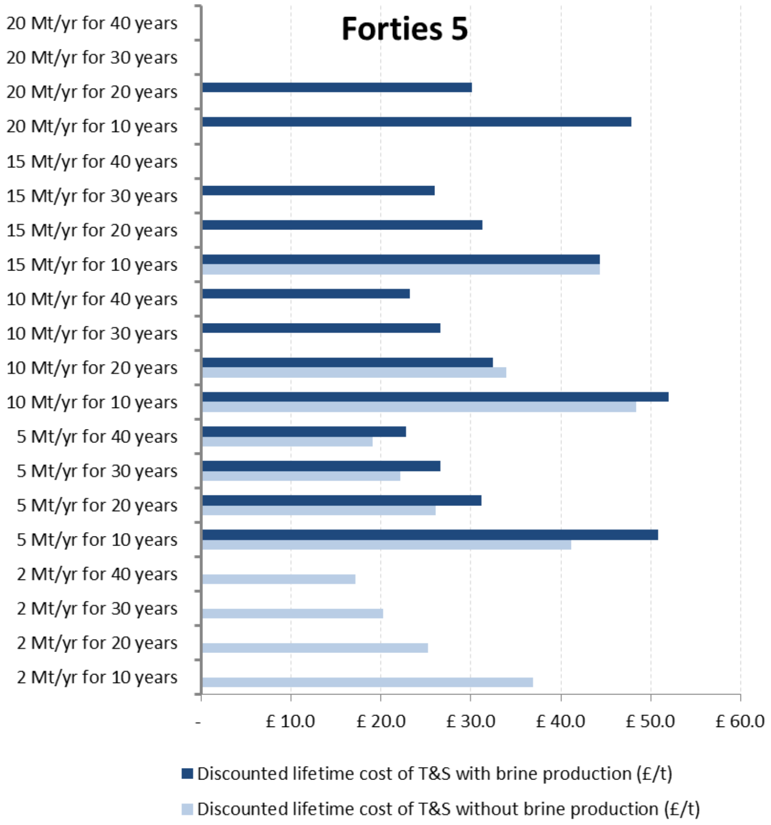


Figure 6: CBA results for Forties

Injection scenario	Undiscounted lifetime cost of T&S without brine production (£/t)	Undiscounted lifetime cost of T&S with brine production (£/t)
2 Mt/yr for 10 years	£ 36.9	-
2 Mt/yr for 20 years	£ 25.3	-
2 Mt/yr for 30 years	£ 20.3	-
2 Mt/yr for 40 years	£ 17.2	-
5 Mt/yr for 10 years	£ 41.2	£ 50.9
5 Mt/yr for 20 years	£ 26.1	£ 31.1
5 Mt/yr for 30 years	£ 22.2	£ 26.6
5 Mt/yr for 40 years	£ 19.1	£ 22.8
10 Mt/yr for 10 years	£ 49.9	£ 52.0
10 Mt/yr for 20 years	£ 36.7	£ 32.4
10 Mt/yr for 30 years	£ 31.8	£ 26.6
10 Mt/yr for 40 years	£ 27.6	£ 23.2
15 Mt/yr for 10 years	£ 44.4	£ 44.3
15 Mt/yr for 20 years	-	£ 31.3
15 Mt/yr for 30 years	-	£ 26.0
15 Mt/yr for 40 years	-	-
20 Mt/yr for 10 years	-	£ 47.9
20 Mt/yr for 20 years	-	£ 30.1
20 Mt/yr for 30 years	-	-
20 Mt/yr for 40 years	-	-

Key results for Forties include the following:

- Brine production is not required for 2Mt/yr of CO_2 injection.
- Maximum practical storage capacity is around 400Mt (10Mt/yr x 40 years) without brine production.
- Total practical capacity increases to 450Mt with brine production. This corresponds to a ~10% increase in total storage capacity.
- Minimum lifetime T&S unit cost (for CO_2 injection rates more than 2Mt/yr) is £19.1/tCO_2 without brine production (5 Mt/yr for 40 years), of which storage cost corresponds to £16.2.
- It should be noted that we present undiscounted costs in this report; however, it is possible to run the same scenarios using a discount factor in the model.
- Lifetime T&S unit costs tend to increase with brine production although some minor savings are observed for “10 Mt/yr for 20 years” and “15 Mt/yr for 10 years”.
- More importantly, more injection scenarios with higher storage capacities become feasible with brine production.

CBA results for Bunter

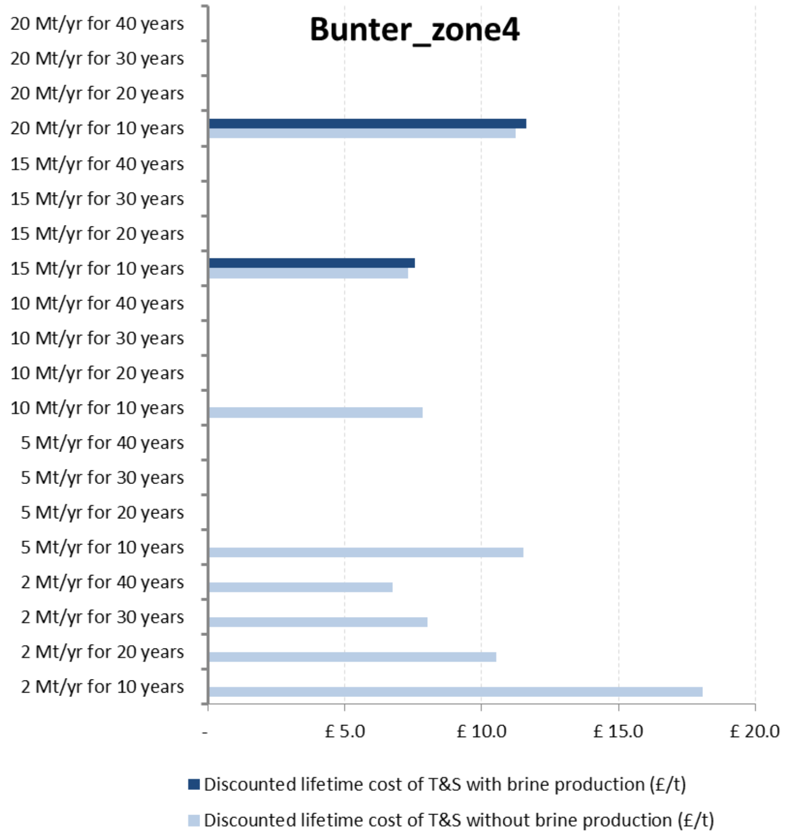


Figure 7: CBA results for Bunter

Injection scenario	Undiscounted lifetime cost of T&S without brine production (£/t)	Undiscounted lifetime cost of T&S with brine production (£/t)
2 Mt/yr for 10 years	£ 18.1	-
2 Mt/yr for 20 years	£ 10.5	-
2 Mt/yr for 30 years	£ 8.6	-
2 Mt/yr for 40 years	£ 6.8	-
5 Mt/yr for 10 years	£ 11.5	-
5 Mt/yr for 20 years	-	-
5 Mt/yr for 30 years	-	-
5 Mt/yr for 40 years	-	-
10 Mt/yr for 10 years	£ 7.8	-
10 Mt/yr for 20 years	-	-
10 Mt/yr for 30 years	-	-
10 Mt/yr for 40 years	-	-
15 Mt/yr for 10 years	£ 7.3	£ 7.5
15 Mt/yr for 20 years	-	-
15 Mt/yr for 30 years	-	-
15 Mt/yr for 40 years	-	-
20 Mt/yr for 10 years	£ 11.2	£ 11.6
20 Mt/yr for 20 years	-	-
20 Mt/yr for 30 years	-	-
20 Mt/yr for 40 years	-	-

Key results for Bunter include the following:

- Brine production is only included for “15 Mt/yr for 10 years” and “20 Mt/yr for 10 years”.
- Maximum practical storage capacity is around 200Mt (20Mt/yr x 10 years) without brine production.
- Total practical capacity does not increase with brine production.
- Minimum lifetime T&S unit cost is £6.8/tCO_2 without brine production (2 Mt/yr for 40 years).
- Lifetime T&S costs increase slightly with brine production.
- There is not any observed benefit in this storage unit.

CBA results for Tay

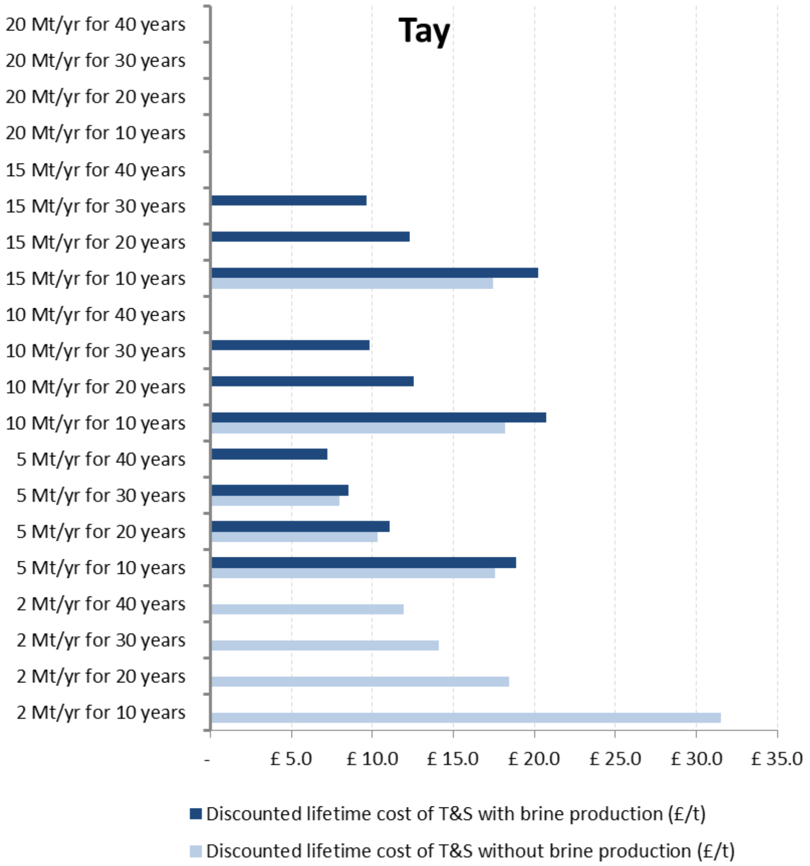


Figure 8: CBA results for Tay

Injection scenario	Undiscounted lifetime cost of T&S without brine production (£/t)	Undiscounted lifetime cost of T&S with brine production (£/t)
2 Mt/yr for 10 years	£ 31.5	-
2 Mt/yr for 20 years	£ 18.5	-
2 Mt/yr for 30 years	£ 14.1	-
2 Mt/yr for 40 years	£ 11.9	-
5 Mt/yr for 10 years	£ 17.5	£ 18.9
5 Mt/yr for 20 years	£ 10.3	£ 11.1
5 Mt/yr for 30 years	**£ 7.9**	£ 8.5
5 Mt/yr for 40 years	-	**£ 7.2**
10 Mt/yr for 10 years	£ 18.2	£ 20.7
10 Mt/yr for 20 years	-	£ 12.6
10 Mt/yr for 30 years	-	£ 9.8
10 Mt/yr for 40 years	-	-
15 Mt/yr for 10 years	£ 17.4	£ 20.2
15 Mt/yr for 20 years	-	£ 12.3
15 Mt/yr for 30 years	-	**£ 9.7**
15 Mt/yr for 40 years	-	-
20 Mt/yr for 10 years	-	-
20 Mt/yr for 20 years	-	-
20 Mt/yr for 30 years	-	-
20 Mt/yr for 40 years	-	-

Key results for Tay include the following:

- Brine production is not required for 2Mt/yr of CO_2 injection.
- Maximum practical storage capacity is around 150Mt (5Mt/yr x 30 years or 15Mt/yr x 10 years) without brine production.
- Total practical capacity triples and increases to 450Mt with brine production.
- Minimum lifetime T&S unit cost is £7.9/tCO_2 without brine production (5 Mt/yr for 30 years), of which storage cost corresponds to £4.8.
- Lifetime T&S unit costs tend to increase for a given injection scenario with brine production similar to Forties and Bunter.
- Similar to Forties, more injection scenarios with higher storage capacities become feasible with brine production. Minimum lifetime T&S unit cost is estimated to be £7.2 with brine production (5 Mt/yr for 40 years). For an injection rate of 5Mt/yr, brine production can increase CO_2 injection duration from 30 years to 40 years as well as reducing lifetime unit T&S cost from £7.9 to £7.2/tCO_2.
- T&S cost of injecting 15 Mt/yr for 30 years with brine production is £9.70/tCO_2 (i.e. £7.70 for storage and around £2 for transport). In order to inject 15Mt/yr for 30 years without brine production, two more storage units similar to Tay would be required.

CBA results for Firth of Forth

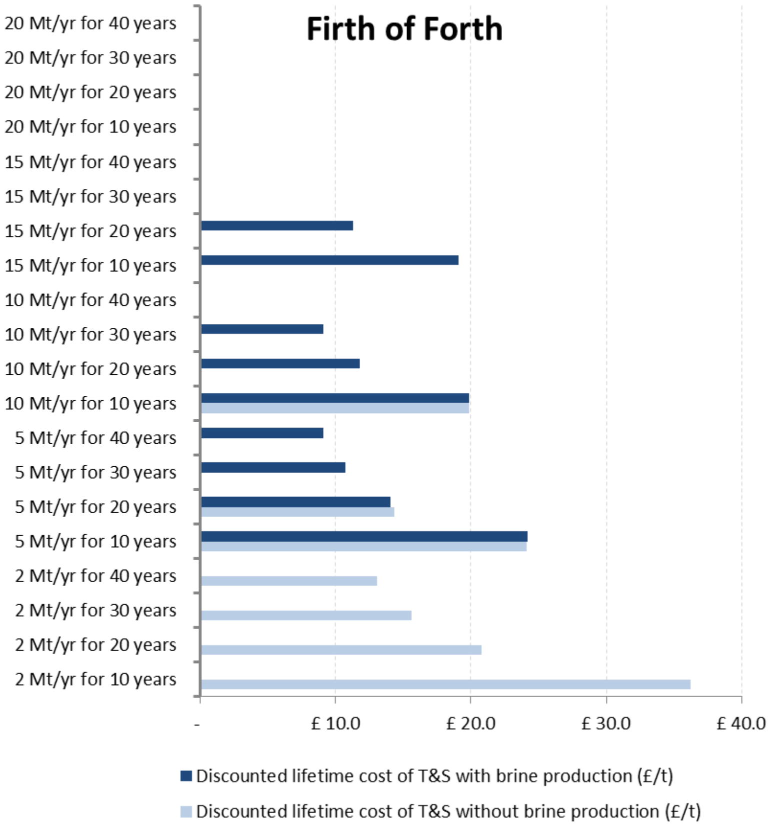


Figure 9: CBA results for Firth of Forth

Injection scenario	Undiscounted lifetime cost of T&S without brine production (£/t)	Undiscounted lifetime cost of T&S with brine production (£/t)
2 Mt/yr for 10 years	£ 36.2	-
2 Mt/yr for 20 years	£ 20.8	-
2 Mt/yr for 30 years	£ 15.6	-
2 Mt/yr for 40 years	**£ 13.1**	-
5 Mt/yr for 10 years	£ 24.1	£ 24.2
5 Mt/yr for 20 years	**£ 14.3**	£ 14.1
5 Mt/yr for 30 years	-	£ 10.7
5 Mt/yr for 40 years	-	**£ 9.1**
10 Mt/yr for 10 years	£ 19.8	£ 19.9
10 Mt/yr for 20 years	-	£ 11.8
10 Mt/yr for 30 years	-	**£ 9.1**
10 Mt/yr for 40 years	-	-
15 Mt/yr for 10 years	-	£ 19.1
15 Mt/yr for 20 years	-	£ 11.3
15 Mt/yr for 30 years	-	-
15 Mt/yr for 40 years	-	-
20 Mt/yr for 10 years	-	-
20 Mt/yr for 20 years	-	-
20 Mt/yr for 30 years	-	-
20 Mt/yr for 40 years	-	-

Key results for Firth of Forth include the following:

- Brine production is not required for 2Mt/yr of CO_2 injection.
- Maximum practical storage capacity is around 100Mt (5Mt/yr x 20 years or 10Mt/yr x 10 years) without brine production.
- Total practical capacity triples and increases to 300Mt with brine production.
- Minimum lifetime T&S unit cost for CO_2 injection rates more than 2Mt/year is £14.3/tCO_2 without brine production (i.e. 5 Mt/yr for 20 years), of which storage cost corresponds to £6.6 and transport is around £7.7.
- Similar to Forties and Tay, more injection scenarios with higher storage capacities become feasible with brine production. Minimum lifetime T&S unit cost is estimated to be £9.1 with brine production (10 Mt/yr for 30 years and 5 Mt/yr for 40 years), which is 30% lower than the minimum cost without brine production.
- In addition to achieving more CO_2 storage capacity with reasonable costs, a lower T&S cost is achieved with brine production at Firth of Forth.

Summary

Table 2: Summary results – Maximum CO_2 storage capacity (Mt)

	Brine production		
	No	Yes	% increase in capacity
Forties 5	400	450	13%
Bunter_zone4	200	200	0%
Tay	150	450	200%
Firth of Forth	100	300	200%

Table 3: Summary results – Minimum undiscounted lifetime cost of T&S (£/tCO_2)

	Brine production	
	No	Yes
Forties 5	£17.2	£22.8
Bunter_zone4	£6.8	£7.5
Tay	£7.9	£7.2
Firth of Forth	£13.1	£9.1

Detailed results for Firth of Forth – 5Mt/yr for 20 years w/o brine production

Cost element	Undiscounted lifetime cost (£million)	Levelised cost (£/t, undiscounted)
Site appraisal	£ 31.0	£ 0.3
Remediate existing wells	-	-
Capex for shoreline compression	£ 19.4	£ 0.2
Capex for distribution hub	-	-
Capex for injection facilities	£ 107.3	£ 1.1
Capex for injection wells	£ 186.6	£ 1.9
Capex for brine production wells	-	-
Capex for brine treatment	-	-
Capex for distribution pipelines	-	-
Capex for cable for offshore boosting	-	-
Capex for transmission pipeline	£ 540.3	£ 5.4
Decommissioning cost	£ 159.9	£ 1.6
Opex for shoreline compression	£ 50.8	£ 0.5
Opex for distribution hub	-	-
Opex for injection facilities	£ 117.0	£ 1.2
Opex for injection wells	£ 110.8	£ 1.1
Opex for brine production wells	-	-
Opex for brine treatment	-	-
Opex for distribution pipelines	-	-
Opex for cable for offshore boosting	-	-
Opex for transmission pipeline	£ 107.5	£ 1.1
Opex for post closure monitoring	£ 0.5	£ 0.0
Total	**£ 1,431.0**	**£ 14.3**

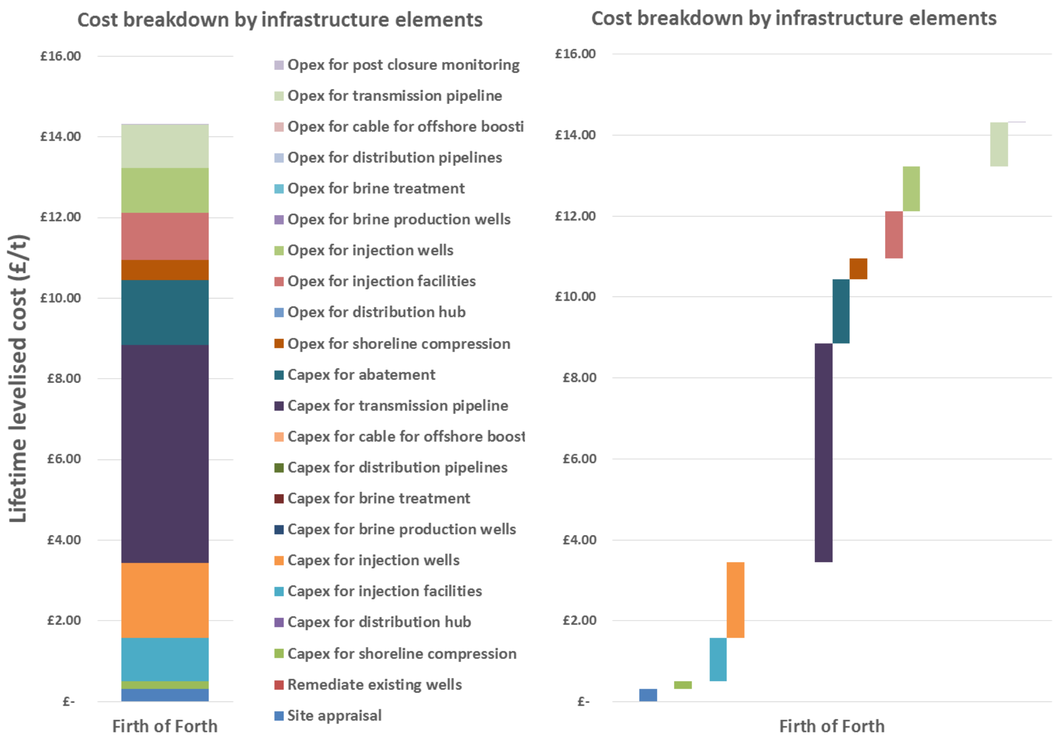


Figure 10: Cost breakdown - Firth of Forth (5Mt/yr for 20 yrs w/o brine production)

Cost element	Infrastructure requirement
Site appraisal	3 km^2
Remediate existing wells	0 wells
Capex for shoreline compression	4 MW
Capex for distribution hub	No hub needed
Capex for injection facilities	1 Medium platform
Capex for injection wells	7 CO_2 injection wells
Capex for brine production wells	0 brine production wells
Capex for brine treatment	0 m^3/d brine production
Capex for distribution pipelines	None needed
Capex for cable for offshore boosting	Not used
Capex for transmission pipeline	Transmission pipeline of length 375 km[1] and diameter 19 inches
Decommissioning cost	Transportation, injection facility and injection well abatement of 10%, 50% and 30%
Opex for post closure monitoring	Post closure monitoring for duration of 20 years

[1] Closes shoreline terminal in the tool is St Fergus. Another shoreline terminal near Grangemouth could be defined in the second phase of the project.

Detailed results for Firth of Forth – 5Mt/yr for 20 years with brine production

Cost element	Undiscounted lifetime cost (£million)	Levelised cost (£/t, undiscounted)
Site appraisal	£ 31.0	£ 0.3
Remediate existing wells	-	-
Capex for shoreline compression	£ 20.3	£ 0.2
Capex for distribution hub	-	-
Capex for injection facilities	£ 107.3	£ 1.1
Capex for injection wells	£ 159.9	£ 1.6
Capex for brine production wells	£ 26.7	£ 0.3
Capex for brine treatment	£ 4.3	£ 0.04
Capex for distribution pipelines	-	-
Capex for cable for offshore boosting	-	-
Capex for transmission pipeline	£ 511.9	£ 5.1
Decommissioning cost	£ 159.3	£ 1.6
Opex for shoreline compression	£ 53.3	£ 0.5
Opex for distribution hub	-	-
Opex for injection facilities	£ 117.0	£ 1.2
Opex for injection wells	£ 95.0	£ 0.9
Opex for brine production wells	£ 15.8	£ 0.2
Opex for brine treatment	£1.7	£ 0.02
Opex for distribution pipelines	-	-
Opex for cable for offshore boosting	-	-
Opex for transmission pipeline	£ 101.9	£ 1.0
Opex for post closure monitoring	£ 0.5	£ 0.01
Total	**£ 1,405.8**	**£ 14.1**

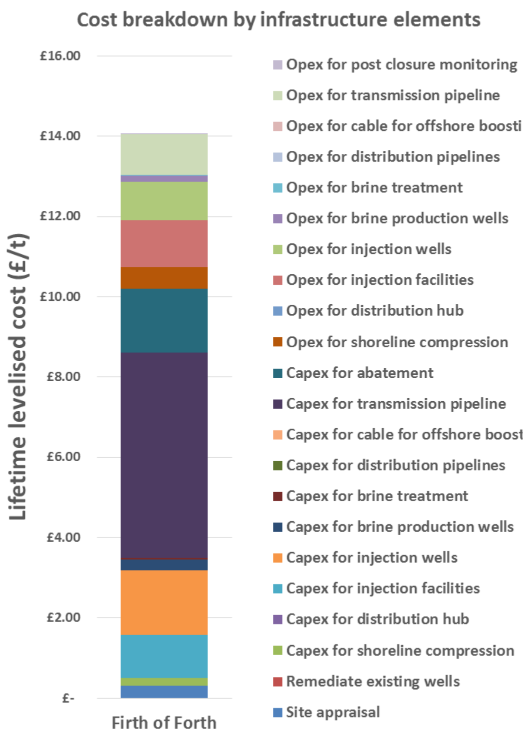


Figure 11: Cost breakdown - Firth of Forth (5Mt/yr for 20 yrs with brine production)

Cost element	Infrastructure requirement
Site appraisal	3 km^2
Remediate existing wells	0 wells
Capex for shoreline compression	4 MW
Capex for distribution hub	No hub needed
Capex for injection facilities	1 Medium platform
Capex for injection wells	6 CO_2 injection wells
Capex for brine production wells	1 brine production wells
Capex for brine treatment	7744 m^3/d brine production
Capex for distribution pipelines	None needed
Capex for cable for offshore boosting	Not used
Capex for transmission pipeline	Transmission pipeline of length 375 km and diameter 18 inches
Decommissioning cost	Transportation, injection facility and injection well abatement of 10%, 50% and 30%
Opex for post closure monitoring	Post closure monitoring for duration of 20 years

Detailed results for Tay – 5Mt/yr for 30 years without brine production

Cost element	Undiscounted lifetime cost (£million)	Levelised cost (£/t, undiscounted)
Site appraisal	£ 38.4	£ 0.3
Remediate existing wells	-	-
Capex for shoreline compression	£ 18.0	£ 0.1
Capex for distribution hub	-	-
Capex for injection facilities	£ 107.3	£ 0.7
Capex for injection wells	£ 159.6	£ 1.1
Capex for brine production wells	-	-
Capex for brine treatment	-	-
Capex for distribution pipelines	-	-
Capex for cable for offshore boosting	-	-
Capex for transmission pipeline	£ 270.3	£ 1.8
Decommissioning cost	£ 124.8	£ 0.8
Opex for shoreline compression	£ 70.6	£ 0.5
Opex for distribution hub	-	-
Opex for injection facilities	£ 175.5	£ 1.2
Opex for injection wells	£ 142.2	£ 0.9
Opex for brine production wells	-	-
Opex for brine treatment	-	-
Opex for distribution pipelines	-	-
Opex for cable for offshore boosting	-	-
Opex for transmission pipeline	£ 80.7	£ 0.5
Opex for post closure monitoring	£ 4.2	£ 0.03
Total	**£ 1,191.6**	**£ 7.9**

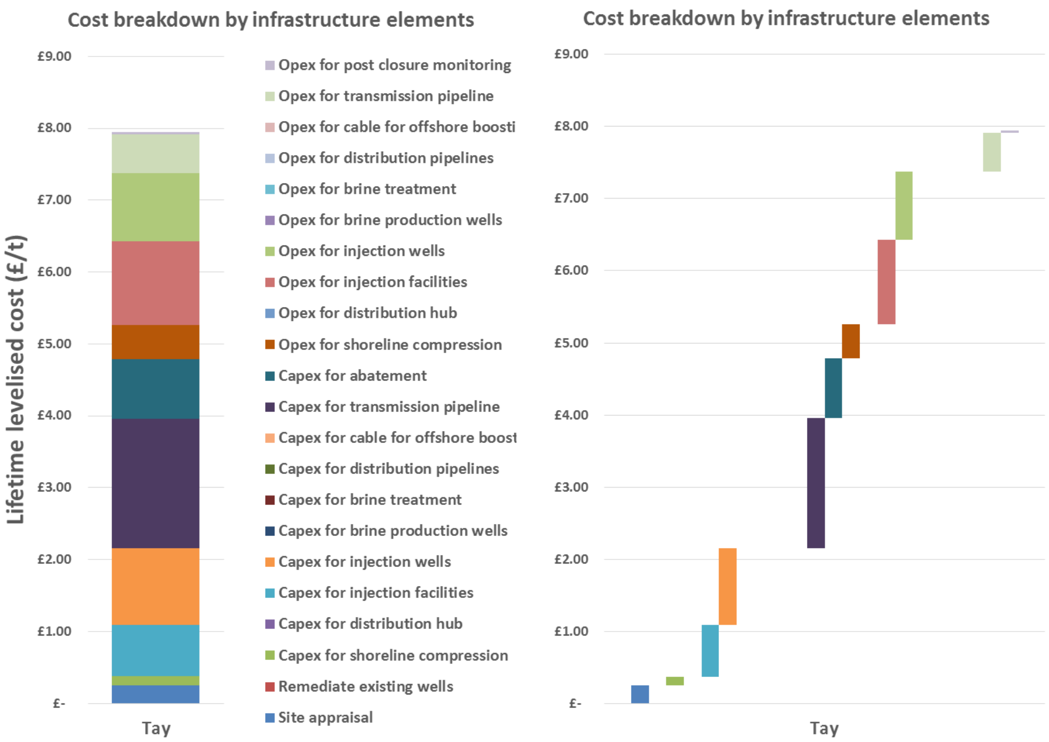


Figure 12: Cost breakdown for Tay (5Mt/yr for 30 years without brine production)

Cost element	Infrastructure requirement
Site appraisal	22 km^2
Remediate existing wells	0 wells
Capex for shoreline compression	4 MW
Capex for distribution hub	No hub needed
Capex for injection facilities	1 Small platform
Capex for injection wells	5 CO_2 injection wells
Capex for brine production wells	0 brine production wells
Capex for brine treatment	0 m^3/d brine production
Capex for distribution pipelines	None needed
Capex for cable for offshore boosting	Not used
Capex for transmission pipeline	Transmission pipeline of length 207 km and diameter 16 inches
Decommissioning cost	Transportation, injection facility and injection well abatement of 10%, 50% and 30%
Opex for post closure monitoring	Post closure monitoring for duration of 20 years

Detailed results for Tay – 15Mt/yr for 30 years with brine production

Cost element	Undiscounted lifetime cost (£million)	Levelised cost (£/t, undiscounted)
Site appraisal	£ 41.0	£ 0.1
Remediate existing wells	-	-
Capex for shoreline compression	£ 54.9	£ 0.1
Capex for distribution hub	£ 78.0	£ 0.2
Capex for injection facilities	£ 386.1	£ 0.9
Capex for injection wells	£ 597.2	£ 1.3
Capex for brine production wells	£ 128.0	£ 0.3
Capex for brine treatment	£ 35.8	£ 0.1
Capex for distribution pipelines	£ 121.1	£ 0.3
Capex for cable for offshore boosting	-	-
Capex for transmission pipeline	£ 427.9	£ 1.0
Decommissioning cost	£ 508.0	£ 1.1
Opex for shoreline compression	£ 216.1	£ 0.5
Opex for distribution hub	£ 70.2	£ 0.2
Opex for injection facilities	£ 842.4	£ 1.9
Opex for injection wells	£ 532.1	£ 1.2
Opex for brine production wells	£ 114.0	£ 0.3
Opex for brine treatment	£ 21.5	£ 0.05
Opex for distribution pipelines	£ 36.3	£ 0.1
Opex for cable for offshore boosting	-	-
Opex for transmission pipeline	£ 127.7	£ 0.3
Opex for post closure monitoring	£ 4.2	£ 0.01
Total	**£ 4,342.7**	**£ 9.7**

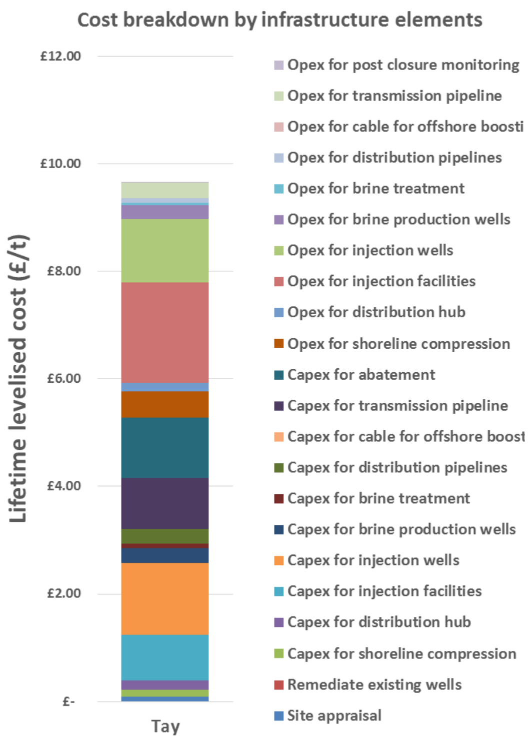


Figure 13: Cost breakdown for Tay (15Mt/yr for 30 years with brine production)

Cost element	Infrastructure requirement
Site appraisal	22 km^2
Remediate existing wells	0 wells
Capex for shoreline compression	11 MW
Capex for distribution hub	Offshore hub of size 15 Mt/y
Capex for injection facilities	9 Subsea facilities
Capex for injection wells	14 CO_2 injection wells
Capex for brine production wells	3 brine production wells
Capex for brine treatment	3556 m^3/d brine production
Capex for distribution pipelines	9 distribution pipelines of length 10 km each and average diameter 10 inches
Capex for cable for offshore boosting	Not used
Capex for transmission pipeline	Transmission pipeline of length 207 km and diameter 25 inches
Decommissioning cost	Transportation, injection facility and injection well abatement of 10%, 50% and 30%
Opex for post closure monitoring	Post closure monitoring for duration of 20 years

Sensitivity analysis on subsea brine production (Firth of Forth and Tay)

The model results presented above are based on an assumption that subsea brine production is possible. It is possible to allow or not allow subsea brine production in the model. In this sensitivity, we examine the impact of “not allowing subsea brine production” on unit T&S costs.

As presented below, not allowing subsea brine production does not have any impact on the costs for Firth of Forth in the model as platforms are already the most cost-effective option. However, not allowing subsea brine production increases costs as subsea injection facilities are the preferred option for Tay (without brine production) in the model. In other words, if platform is a viable option without brine production, allowing subsea brine production does not lead to any cost savings.

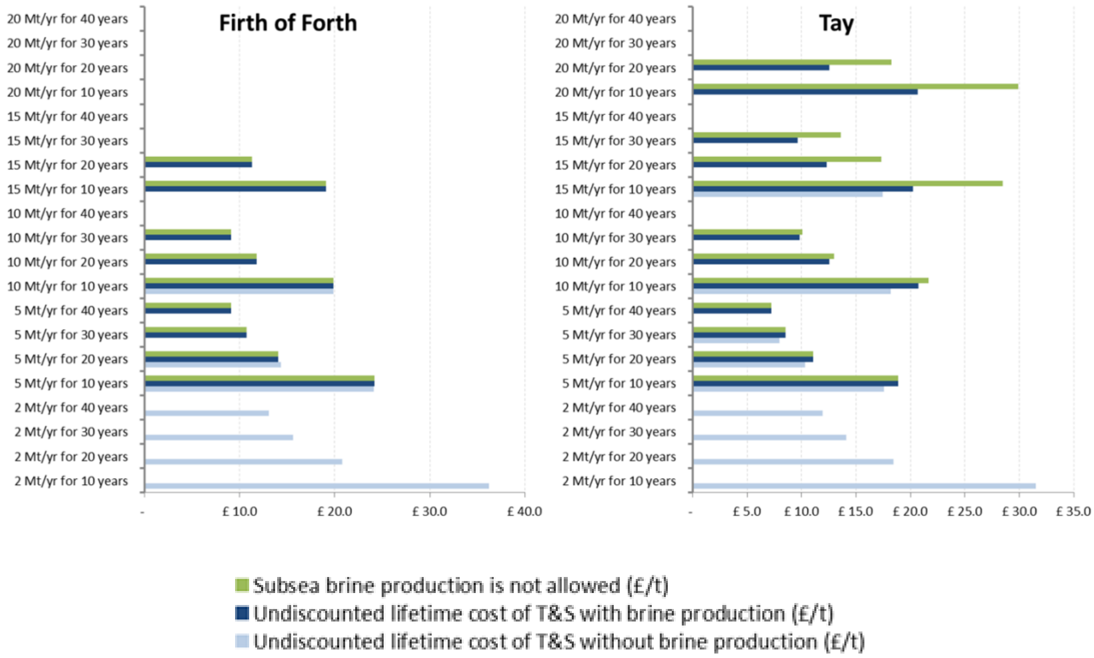


Figure 14: Sensitivity analysis on subsea brine production (Firth of Forth and Tay)

Sensitivity analysis on subsea brine production, oil separation and manned platform (Tay, 15Mt/yr, 30 years, with brine production)

As explain in the previous sensitivity, not allowing subsea brine production increases costs for Tay. In this sensitivity we examine the increase in costs in more detail in addition to the potential impact of “oil separation” and “manned platforms”.

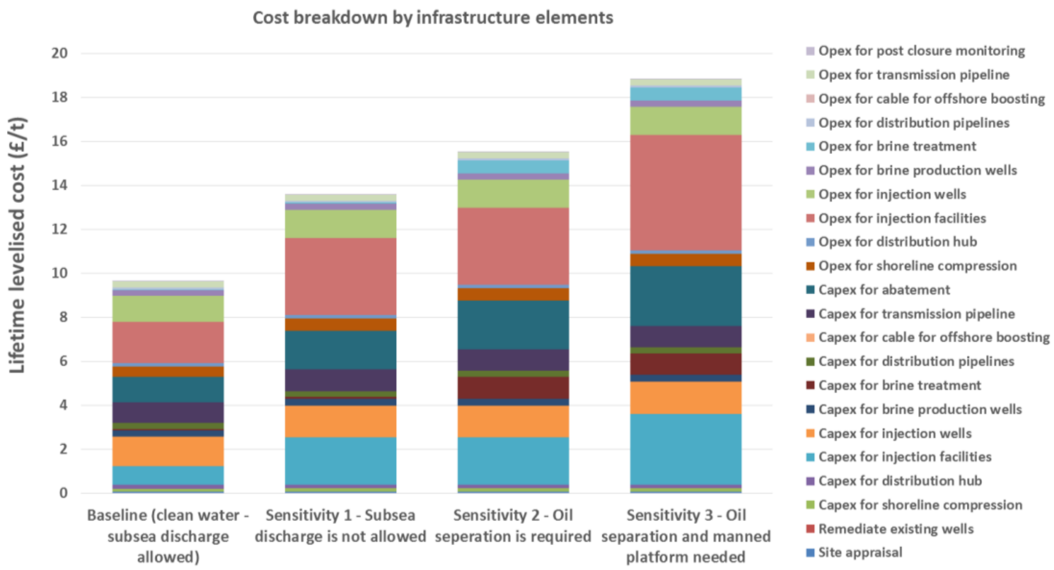


Figure 15: Sensitivity analysis on subsea brine production, oil separation and manned platform (Tay, 15Mt/yr, 30 years, with brine production)

As CAPEX of clean water discharge infrastructure on platform corresponds to £0.10/tCO_2 only, sub-sea brine production does not lead to significant savings in water treatment CAPEX. However, significant savings can be achieved in injection facility CAPEX. This will be explored further in the second phase of the project (e.g. using a central water treatment facility, which can be connected to subsea facilities or oversea platforms via brine distribution pipelines).

If both oil separation and manned platform are needed, lifetime levelised cost almost doubles compared to Baseline.

5 Key findings and next steps

Key findings:

- **Value of brine production:** Lifetime T&S unit costs tend to increase with brine production for a given injection scenario (although some minor savings are observed for some of the units examined); however, more importantly, more injection scenarios with higher storage capacities become feasible with brine production.

- **Cost effectiveness of brine production:** Brine production allows significant increase in storage capacity at similar unit costs. In addition to achieving more CO_2 storage capacity with reasonable costs, a lower unit T&S cost is achieved with brine production at Firth of Forth and Tay.

- **Optimal development/configuration plans:** As CAPEX of clean water discharge infrastructure on platform is negligible, sub-sea brine production does not lead to significant savings in water treatment CAPEX. However, significant savings can be achieved in injection facility CAPEX (if high costs of installing platforms can be avoided with subsea brine production – e.g. if subsea facilities connected to a hub is the most cost-effective configuration for an injection scenario).

Next steps:

- **Value and cost of brine production:** Examination of potential impact of brine production on gas fields

- **Optimal development/configuration plans:** Examination of further brine production scenarios that will be provided by HWU (e.g. more optimised injection/brine production scenarios if necessary) and examining different infrastructure configurations with brine production (e.g. using a central water treatment facility, which can be connected to subsea facilities or oversea platforms via brine distribution pipelines

- **Informing CO_2Stored database:** Reviewing learnings from the initial analysis to consider how we could model other storage units in the CO_2Stored database

6 Appendix: Key engineering assumptions and cost datasets

6.1 CO_2 injection and brine production wells

- Brine production wells are assumed to be corrosion resistant and have costs similar to the CO_2 injection wells.
- Well length is calculated based on well depth, well position data from HWU (i.e. grid length and width) and injection facility configuration.
- Data on number of CO_2 injection and brine production wells, and predicted downhole pressure have been provided by HWU.
- The number of wells was augmented to allow for redundancy in the event of routine operating and maintenance. The well redundancy was estimated as:
    - If number of CO_2 injection wells required for injection scenario is less than 10, one additional well required. Otherwise, number of additional wells required is assumed to be 10%.
- Redundancy wells are not included for brine production i.e. its value is set to 0% in the model but model has option for increasing wells for redundancy.
- Fixed CAPEX and variable CAPEX of wells have been estimated using the detailed well cost estimates in the ETI Strategic UK CCS Storage Appraisal Project.
- Subsea wells are assumed to be 25% more expensive compared to the platform well costs below (as suggested by Trevor Jones).

Table 4: Well unit costs

Fixed capex (£)	Variable capex (£/m)	Opex (share of capex)
£10,000,000	£3,600	3%

6.2 Water treatment facilities

- Oil fields: All oil fields require oil separation and platforms might need to be manned due to the DECC regulations as water samples need to be taken twice daily.
- Aquifers and gas fields: Aquifers and gas fields do not require oil separation so a basic water discharge facility is sufficient. Platforms can be unmanned as there are no specific regulations.
- Sub-sea brine production is allowed in the baseline for clean water displacement but subsea monitoring costs are highly uncertain due to limited practical experience. Platform water treatment costs are used for subsea brine production. A sensitivity analysis was carried out to examine the impact of not allowing subsea brine production on costs.
- It is possible to change these base case assumptions in the model.
- Power requirement for water treatment is negligible as water is flowing from high pressure to low pressure.
- Brine production stops in case of CO_2 breakthrough so CO_2 recycling facilities are not needed.
- Water treatment costs were provided by Trevor Jones. .

Table 5: Water treatment unit costs

Water treatment scenarios	Infrastructure elements	Fixed cost (£)	Marginal cost (£ per 100,000 brine per day)	OPEX	Comments
"Clean" aquifer water discharged to sea	a. Tank with level control b. Water testing station c. Caisson	£2,800,000	£1,200,000	2% of CAPEX	IGF vessel and a dedicated water disposal caisson
Oil removal required	a. Skimmer b. Hydrocyclone c. IGF & IGF pump d. Caisson (water dump) e. Contingency for collecting, storing and offloading oil	£32,200,000	£13,800,000	2% of CAPEX	Based on overboard discharge of one of installations in Denmark.

6.3 Platforms, hubs and subsea facilities

- The platform facility functional requirements are likely to include wellheads and manifolding, well workover capability, temporary accommodation (facility would not normally be manned), crane, and helideck. It is assumed that the CO_2 arrives dry, so that carbon steel facilities can be used.
- Base case assumptions:
    - Oil fields: Platforms will need to be manned due to the DECC regulations as water samples need to be taken daily
    - Aquifers and gas fiels: Platforms can be unmanned as there are no specific regulations
    - User will be able to change these base case assumptions
- Area accessible from a single platform is assumed to be around 5-6 km radius:
    - Less than 5 km radius: one platform/injection facility
    - More than 5km radius: hub with several subsea injection facilities (or platforms if more cost effective)
- Platform CAPEX figures below are consistent with CO_2NomicA; however, OPEX fractions have been updated based on a review of the detailed costs developed by the ETI Strategic UK CCS Storage Appraisal Project.
- Manned platform CAPEX is assumed to be 50% more compared to the unmanned platform costs below (as suggested by Trevor Jones).

Table 6: Injection facility unit costs

Description	Shallow (< 100 m)	Medium (100-150 m)	Deep (>150m)	Opex (% of capex)
Subsea	£20,000,000	£30,000,000	£40,000,000	8%
Small platform - 6 wells	£50,000,000	£75,000,000	£100,000,000	6%
Medium platform - 12 wells	£75,000,000	£112,500,000	£150,000,000	6%
Large platform - 20 wells	£100,000,000	£150,000,000	£200,000,000	6%

- Where there is a requirement for distribution pipelines to connect multiple injection facilities to the transmission pipeline, the capital and operating costs for a platform hub are included. Where offshore boosting is required, the cost of this is reflected in the increased capital and operating cost of the hub, as well as power via cable from shoreline.
- Annual OPEX = 2% of CAPEX (no boosting) and 3% of CAPEX (if there is boosting)
- The baseline cost of power cables is modelled as £500,000/km.
- The length of the power cables is taken as the same as the transmission pipeline.
- Booster energy cost at the shoreline is modelled as £52/MWh (consistent with the ETI Strategic UK CCS Storage Appraisal Project) and as a simplification, a 10% loss in energy is assumed for all offshore cables.

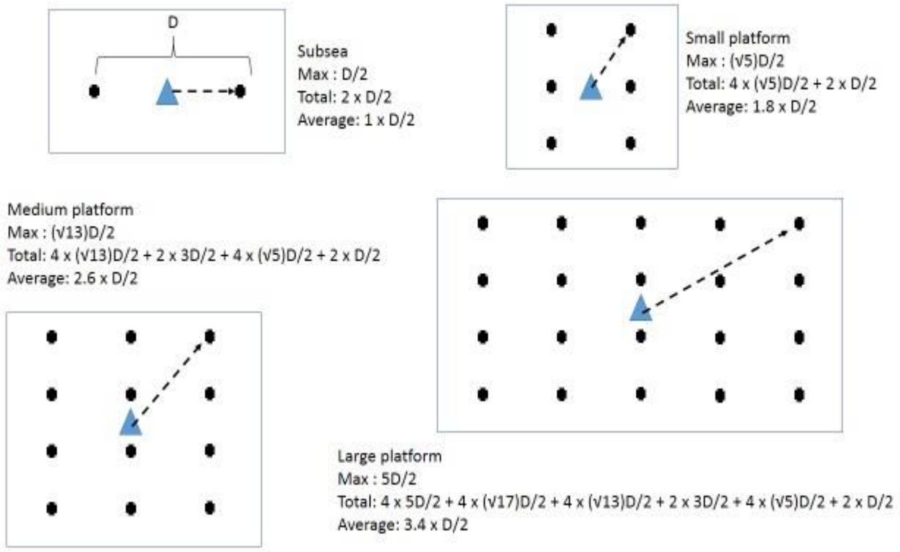
Table 7: Hub unit costs

	No boosting	Flow rate with boosting (Mt CO_2/yr)						
	0	2	5	10	15	20	40	60
Water depth < 100 m	£50m	£55m	£55.8m	£57.2m	£58.6m	£60m	£65.2m	£70m
Water depth 100-150m	£60m	£65m	£65.8m	£67.2m	£68,6m	£70m	£75.2m	£80m
Water depth > 150m	£65m	£70m	£70.8m	£72.2m	£73.6m	£75m	£80.2m	£85m

Opex (% of capex) - with boosting	3%
Opex (% of capex) - without boosting	2%

6.4 Injection infrastructure configuration

The model assumes the CO_2 injection and brine production wells are located equidistant and in a rectangular grid. Furthermore, the CO_2 and brine wells are assumed to use the same injection facilities (subsea or platform). The injection facility is assumes to be located at the centre of the rectangular grid. Therefore, the distance of individual wells to the injection facility varies. Based on the 4 injection facilities available in the model, the average and maximum distances are calculated for each configuration, as show below.



All of these distances are calculated relative to the average well spacing 'D', which is calculated in the following manner:

1. The average grid area per well 'A' is calculated using the length and width of the well grid arrangement and the total number of wells
2. The spacing between wells 'D' is calculated as √A

The number of facilities needed are calculated based on maximum wells per facility. If more than 1 injection facility is needed, a hub is assumed to be located at the centre of injection zone. The length of distribution pipeline are based on average radial distance to facilities, calculated as ¼ of average grid length and width dimensions. The number of distribution pipelines is same as number of facilities.

6.5 Transmission and distribution pipelines

- The distance from sink to the nearest shoreline terminal is calculated from the latitude and longitude of the centroid of the unit polygon (as recorded in the CO_2 Stored database) and the nearest shoreline hub using the spherical law of cosines.
- A routing factor of 1.2 was applied to convert straight-line distances to pipeline lengths.
- Transmission diameter size is calculated assuming pressure drop should not exceed 15 MPa.
- It is assumed that the CO_2 is delivered at 10 MPa at the required purity to the shoreline boosting hubs for offshore pipeline transport and geological storage and compressed to 25 MPa.
- Capital cost of transmission pipeline = pipeline length x routing factor x cost per km.inch x inner diameter
- Capital costs shown below are consistent with CO_2Nomica; however, 30% contingency has been removed as contingency is shown separately in this tool.

Table 8: Locations of shoreline terminals

Shoreline terminal	Latitude	Longitude

Bacton	52.86	1.46
Barrow	54.09	-3.18
Easington Shore	53.65	0.12
Forth	56.01	-3.69
Humber	53.36	0.23
Milford Haven	51.7	-5.08
St Fergus	57.58	-1.84
Teesside	54.61	-1.19
Thames	51.44	0.69
Wirral	53.34	-3.32

Table 9: Transmission pipeline unit costs

Transmission pipeline length (km)	Capex (£/inch/km)	Transmission pipeline length (km)	Capex (£/inch/km)
1	£180,288	**200**	£62,600
25	£154,247	**250**	£60,096
30	£138,555	**300**	£58,093
40	£116,436	**400**	£55,965
50	£103,165	**500**	£54,587
60	£93,483	**600**	£53,669
80	£82,632	**700**	£53,085
100	£76,122		
150	£67,107	**Opex (share of capex)**	1%

Pressure drop (Mpa/km) in pipeline can be derived in a four step calculation that links flow rate (Mt CO_2/y) to pipeline diameter size (inches), this involves the following steps:

- The Reynolds number, Re, is calculated from density (ρ in kg/m3), velocity (v in m/s), diameter (D in m) and dynamic viscosity (μ in Pa.s)

$$\mathrm{Re} = \rho v D / \mu$$

- The Darcy-Weisbach friction factor, f, is calculated from the diameter (D in m), roughness height (e in m) and Reynolds number

$$f = 1.325 / \left[\ln((e/3.7D) + (5.74/\mathrm{Re}^{0.9}))\right]^2$$

- The Moody friction factor fF is calculated from the Darcy-Weisbach friction factor f

$$f_F = f/4$$

- Neglecting topographic differences, the pressure drop per metre (Δp/L in N/m3) is calculated from the Moody friction factor, the mass flow rate Qm, the density, and the diameter

$$\Delta p / L = \frac{32 f_F Q_m^{\ 2}}{\rho \pi^2 D^5}$$

Pressure drop (MPa/km)

	Flow rate (Mt CO_2 /y)											
Pipeline diameter (inches)	0.001	0.25	0.35	0.5	0.75	1	1.5	2	3	4.5	6.5	9
4.5	1.99E-06	5.26E-02	1.02E-01	2.07E-01	4.63E-01	8.21E-01	1.84E+00	3.27E+00	7.34E+00	1.65E+01	3.44E+01	6.59E+01
6	5.13E-07	1.20E-02	2.32E-02	4.68E-02	1.04E-01	1.84E-01	4.13E-01	7.31E-01	1.64E+00	3.68E+00	7.68E+00	1.47E+01
8	1.33E-07	2.77E-03	5.32E-03	1.07E-02	2.36E-02	4.17E-02	9.30E-02	1.64E-01	3.68E-01	8.26E-01	1.72E+00	3.29E+00
10	4.71E-08	8.97E-04	1.71E-03	3.41E-03	7.52E-03	1.32E-02	2.94E-02	5.19E-02	1.16E-01	2.60E-01	5.40E-01	1.03E+00
12	2.02E-08	3.59E-04	6.82E-04	1.35E-03	2.97E-03	5.20E-03	1.15E-02	2.03E-02	4.52E-02	1.01E-01	2.10E-01	4.01E-01
14	9.87E-09	1.67E-04	3.15E-04	6.22E-04	1.36E-03	2.37E-03	5.23E-03	9.19E-03	2.04E-02	4.56E-02	9.46E-02	1.81E-01
16	5.32E-09	8.61E-05	1.62E-04	3.18E-04	6.92E-04	1.20E-03	2.65E-03	4.64E-03	1.03E-02	2.29E-02	4.74E-02	9.05E-02
18	3.09E-09	4.81E-05	9.03E-05	1.77E-04	3.83E-04	6.64E-04	1.45E-03	2.55E-03	5.63E-03	1.25E-02	2.59E-02	4.93E-02
20	1.90E-09	2.87E-05	5.36E-05	1.05E-04	2.26E-04	3.91E-04	8.53E-04	1.49E-03	3.29E-03	7.28E-03	1.50E-02	2.86E-02
22	1.23E-09	1.80E-05	3.36E-05	6.53E-05	1.40E-04	2.42E-04	5.27E-04	9.19E-04	2.02E-03	4.47E-03	9.22E-03	1.75E-02
24	8.22E-10	1.18E-05	2.19E-05	4.25E-05	9.10E-05	1.57E-04	3.40E-04	5.92E-04	1.30E-03	2.87E-03	5.90E-03	1.12E-02
26	5.69E-10	7.96E-06	1.48E-05	2.87E-05	6.12E-05	1.05E-04	2.28E-04	3.96E-04	8.66E-04	1.91E-03	3.92E-03	7.43E-03

Figure 16: Pressure drop table

- The cost of distribution pipelines is calculated as a function of length and diameter. As a simplification, the average length of distribution pipelines is estimated based on the well distance data that will be provided by HWU.
- A routing factor of 1.2 was used to correct the pipeline length from the calculated "straight line" distance.
- Where no. of injection facilities > 1, number of distribution pipelines = no of subsea injection facilities.
- Where no of injection facilities =1, no distribution pipelines are required.
- Distribution pipeline diameter size is calculated to meet the well head pressure.
- Average capital cost per distribution pipeline = Average pipeline length x routing factor x cost per km.inch x inner diameter

Table 10: Distribution pipeline unit costs

Distribution pipeline length (km)	Capex (£/inch/km)	Distribution pipeline length (km)	Capex (£/inch/km)
0.1	£362,847	**20**	£79,297
2	£213,542	**30**	£74,306
4	£138,889	**40**	£71,832
7	£107,019	**50**	£70,347
10	£94,184		
15	£84,259	**Opex (share of capex)**	1%

6.6 Shoreline boosting

- Onshore sites are assumed to be connected to a shoreline hub through an onshore pipeline or pipeline network. The details of the onshore network are not examined. The model begins at a shoreline hub, where it is assumed that the CO_2 is delivered at 10 MPa at the required purity for pipeline transport and geological storage.
- The required wellhead pressure corresponds to the pressure at the end of the pipeline. The required pressure at the shoreline can then be computed based on total pressure drop along the pipeline (pressure drop per metre x distance) and required wellhead pressure.

- For each injection scenario, HWU provided downhole pressures, from which well head pressure can be estimated. Wellhead (surface) pressure is calculated based on downhole pressure, gravity head and pressure loss along the well due to friction.
- $P_{surface} = P_{down} – P_{grav} + \Delta P_{friction}$
- The power required for boosting is modelled according to the following equation:
- $$Power = \frac{Flowrate.}{Efficiency} \times \Delta P$$
- If flow rate is in kg/s and the pressure difference in MPa, then power is in MW.
- In the baseline scenario, the cost of boosting is estimated at £3,750,000 per MW.
- Booster efficiency is modelled as 75%.
- Annual opex is modelled as 4% of capex.
- The baseline cost of energy for boosting is modelled as £52/MWh.

6.7 Site appraisal

- For aquifers, the cost of seismic assessment was estimated at £31,250/km^2 in the UKSAP study.
- The assumption on the appraisal well requirement has been updated based on the ETI Strategic UK CCS Storage Appraisal Project. In this CBA tool, it is assumed that one appraisal well is sufficient.
- Hydrocarbon fields are assumed to have considerable data already available appraisal wells are not required. The cost of site appraisal for hydrocarbon fields has been estimated based on the ETI Strategic UK CCS Storage Appraisal Project. For hydrocarbon fields, the cost of seismic assessment has been estimated at £17,500/km^2
- No re-use of appraisal wells is modelled.

6.8 Monitoring and abatement costs

Abatement and monitoring costs have been estimated based on the outcomes of the ETI Strategic UK CCS Storage Appraisal Project. Annual OPEX for monitoring is included in the tool assuming a Seismic every 5 years (i.e. annual monitoring costs = Seismic cost / 5). Similarly, monitoring costs are included throughout the projects and for 20 years after closure.

Table 11: Monitoring and abatement costs

Transportation abatement	10%	of CAPEX
Injection facility abatement	50%	of CAPEX
Injection well abatement	30%	of CAPEX
Post closure monitoring duration	20	years
Monitoring frequency	5	years

6.9 Pre-FID costs and contingency

A contingency of 30% is added on all costs consistent with the ETI Strategic UK CCS Storage Appraisal Project estimates. Pre-FID costs have also been estimated based on the Appraisal work.

Table 12: Pre-FID costs and contingency

Transportation pre-FID (incl. Pre-FEED / FEED Design and Engineering)	0.5%	of CAPEX
Injection facility pre-FID (incl. Pre-FEED / FEED Design and Engineering)	10%	of CAPEX
Well pre-FID (incl. Pre-FEED / FEED Design and Engineering)	1%	of CAPEX
Contingency	30%	of all costs

7 Appendix: Limitations, future work recommendations and arising IP

Limitations

- Currently the model assumes point-to-point T&S infrastructure for all storage units. Some storage units are geographically close to each other and can benefit from over-sized pipelines and an offshore network connecting storage units, thereby reducing overall transportation costs.
- Storage unit costs are based on high-level assumptions on infrastructure element costs. In reality, T&S costs might be different due to site-specific and project-specific issues.
- Model does not include any re-use of existing infrastructure.
- All water treatment facilities are assumed to be on a platform. Sub-sea treatment facilities exist but costs are highly uncertain due to limited practical experience. Sub-sea treatment facilities can be used in the tool as a sensitivity using the same cost dataset with platform treatment facilities.
- Management of CO_2 phase (e.g. temperature control, accommodating changes in topography) is beyond the scope of this tool.

Future work recommendations

- Applying learnings from the initial analysis to model other storage units in the CO_2Stored database
- Examining different infrastructure configurations with brine production (e.g. using a central water treatment facility, which can be connected to subsea facilities or oversea platforms via brine distribution pipelines)
- Including offshore networks to connect storage sites using a single large or multiple parallel pipelines with phased investment (similar to CO_2NomicA).

Arising IP

Cost datasets and methodology for transport and storage economics developed by Element Energy during UKSAP and CO_2NomicA have been used and updated as necessary with the engineering and cost requirements for brine production. Some of the previous cost datasets have been updated based on a review of the detailed transport and storage costs developed by the Strategic UK CCS Storage Appraisal Project. The following table summarises Arising IP in this task.

Table 13: Arising IP

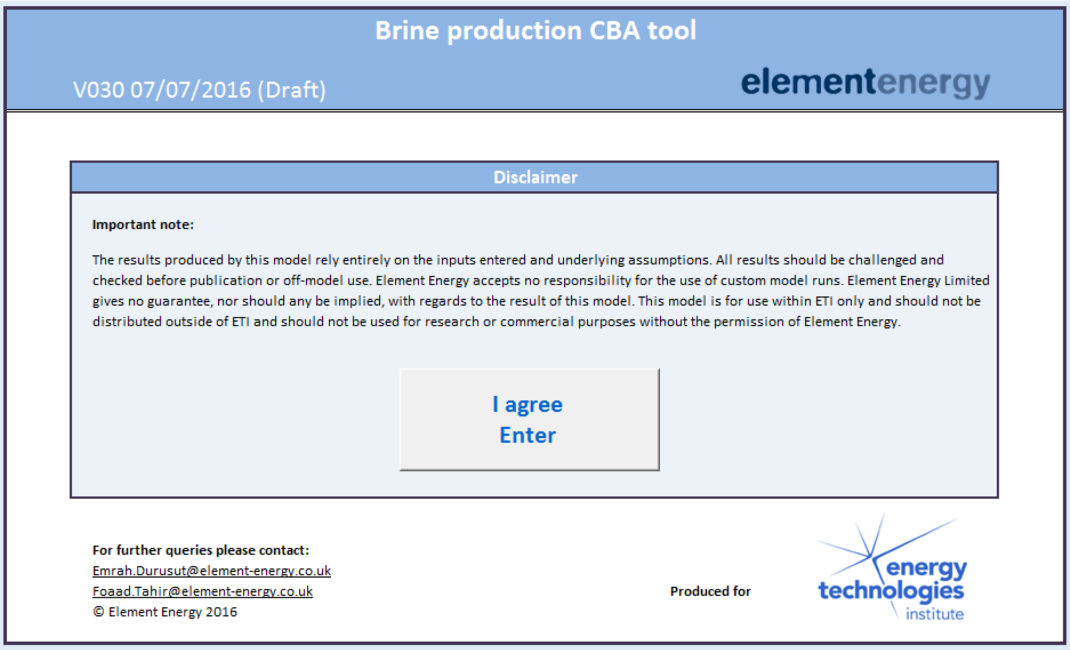
Arising IP	Description	Comments
Brine Production CBA Tool including the user interface	Excel model	Developed in this project
Well unit costs	Cost dataset	Derived based on a review of the ETI Strategic UK CCS Storage Appraisal Project
Water treatment facility unit costs	Cost dataset	Developed in this project
Injection infrastructure configuration methodology	Methodology	Developed in this project
Seismic cost for hydrocarbon fields	Cost dataset	Derived based on a review of the ETI Strategic UK CCS Storage Appraisal Project
Monitoring costs	Cost dataset	Derived based on a review of the ETI Strategic UK CCS Storage Appraisal Project
Abatements costs	Cost dataset	Derived based on a review of the ETI Strategic UK CCS Storage Appraisal Project
Pre-FID costs	Cost dataset	Derived based on a review of the ETI Strategic UK CCS Storage Appraisal Project
Outputs of the Brine Production CBA Tool	Study output	Developed in this project

8 Appendix: Model user manual

This section explains how the user should operate the tool to examine costs and benefits (i.e. cost reduction and/or storage increase) of brine production.

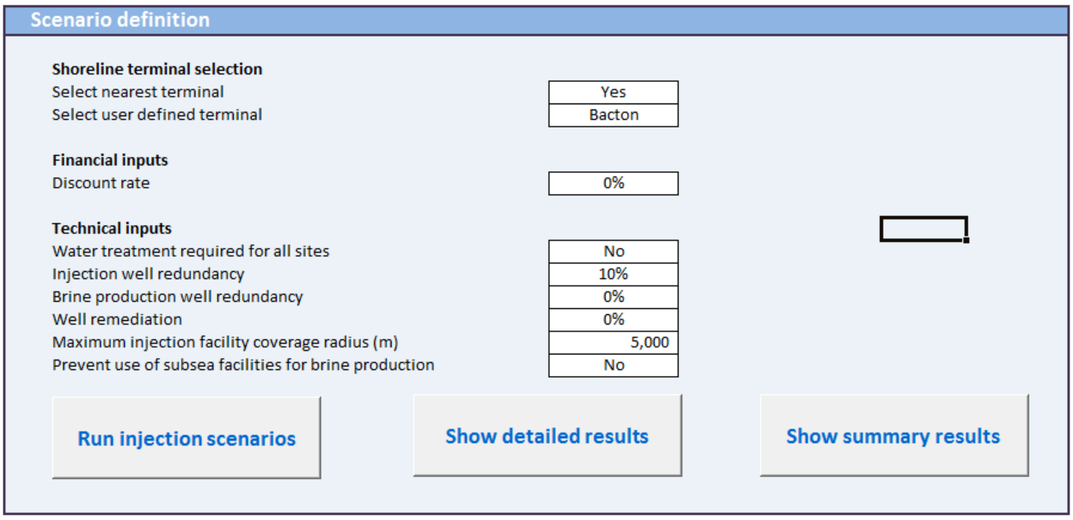
Front page

The model takes the user to the disclaimer page on the model start up. This page informs the user about the model limitations, conditions of use and contact details of developers. The user should click on the 'I agree, Enter" button to proceed with the use of the model.



Control page – Scenario definition

"Control panel" is the page from where the user can define a scenario, run the model, and jump to the results pages. The screenshot below shows the top panel in the Main control page, where the user can set the generic scenario inputs including shoreline terminal selection, discount rate, and further technical inputs for running sensitivities.



On the Main control page, the user can run the model using the “Run injection scenarios” button, as shown above. After running all injection scenarios as defined in the “Well requirements sheet” for all pre-defined storage units, the user has the option to view detailed and summary results of the run by pressing the “Show detailed results” and “Show summary results” buttons.

Control page – Analysis for selected storage site and injection scenario

The screenshot below shows the second panel on the Main control page, which can be used to examine a selected storage unit and injection scenario in more detail. Here, the user can choose a pre-defined storage site, flow rate, injection duration, brine production status (Yes/No), Well type (Vertical/Horizontal) and Well conversion status (Yes/No). Please note that, the results of individual units are limited by the detailed technical data included in the model. E.g. if technical data for horizontal wells are not included in the “Well requirements” sheet, the model will show blank results. Once a scenario is defined, the table below shows existing inputs from the “Well requirements” sheet, which can be over-written by the user.

The “Show results for selected storage unit” button takes the user to the “Individual storage unit” page.

Analysis for selected storage site and injection scenario

Storage site	Forties 5
Flow rate (Mt CO2/y)	5
Injection duration (years)	40
Brine production status	No
Well type	Horizontal
Well conversion status	No

	Existing input	User defined	Final used
CO2 injection wells (including redundancy)	24		24
Converted CO2 injection wells	0		0
Brine production wells (including redundancy)	0		0
Bottom hole pressure (MPa)	39.00		39.00
Grid length (m)	6000		6000
Grid width (m)	16800		16800
Average well depth (m)	2,750		2,750
Maximum brine production (m3/d)	0		0

Show results for selected storage unit

Summary outputs page

The screenshot below shows the summary outputs of the model for each storage unit.

Brine production CBA tool

Summary outputs

Main control page

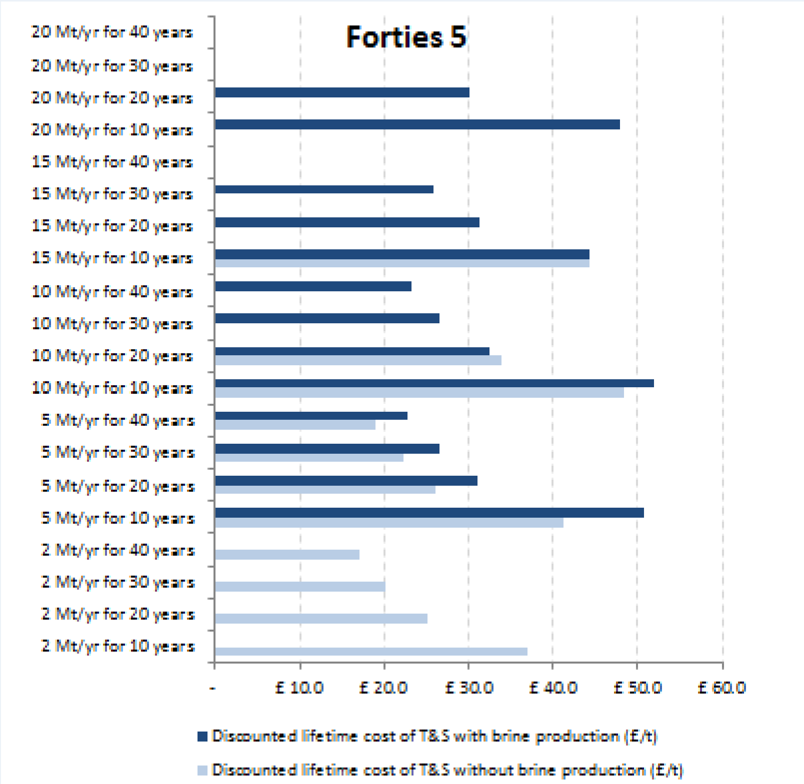
Maximum CO2 storage capacity (Mt)

	Brine production		
	No	Yes	increase in capaci
Forties 5	200	450	125%
Bunter_zone4	200	200	0%
Tay	150	450	200%
Firth of Forth	100	300	200%

Minimum lifetime cost of T&S (£/tCO2)

	Brine production	
	No	Yes
Forties 5	£ 17.2	£ 22.8
Bunter_zone4	£ 6.8	£ 7.5
Tay	£ 7.9	£ 7.2
Firth of Forth	£ 13.1	£ 9.1

Description	Flow rate (Mt CO2/y)	Injection duration (years)	Injection scenario	Discounted lifetime cost of T&S without brine	Discounted lifetime cost of T&S with brine
Forties 5	2	10	2 Mt/yr for 10 years	£ 36.9	-
Forties 5	2	20	2 Mt/yr for 20 years	£ 25.3	-
Forties 5	2	30	2 Mt/yr for 30 years	£ 20.3	-
Forties 5	2	40	2 Mt/yr for 40 years	£ 17.2	-
Forties 5	5	10	5 Mt/yr for 10 years	£ 41.2	£ 50.9
Forties 5	5	20	5 Mt/yr for 20 years	£ 26.1	£ 31.1
Forties 5	5	30	5 Mt/yr for 30 years	£ 22.2	£ 26.6
Forties 5	5	40	5 Mt/yr for 40 years	£ 19.1	£ 22.8
Forties 5	10	10	10 Mt/yr for 10 years	£ 48.4	£ 52.0
Forties 5	10	20	10 Mt/yr for 20 years	£ 34.0	£ 32.4
Forties 5	10	30	10 Mt/yr for 30 years	-	£ 26.6
Forties 5	10	40	10 Mt/yr for 40 years	-	£ 23.2
Forties 5	15	10	15 Mt/yr for 10 years	£ 44.4	£ 44.3
Forties 5	15	20	15 Mt/yr for 20 years	-	£ 31.3
Forties 5	15	30	15 Mt/yr for 30 years	-	£ 26.0
Forties 5	15	40	15 Mt/yr for 40 years	-	-
Forties 5	20	10	20 Mt/yr for 10 years	-	£ 47.9
Forties 5	20	20	20 Mt/yr for 20 years	-	£ 30.1
Forties 5	20	30	20 Mt/yr for 30 years	-	-
Forties 5	20	40	20 Mt/yr for 40 years	-	-



Results for selected storage unit

The screenshot below shows the detailed cost breakdown of infrastructure elements for user selected storage site.

Brine production CBA tool

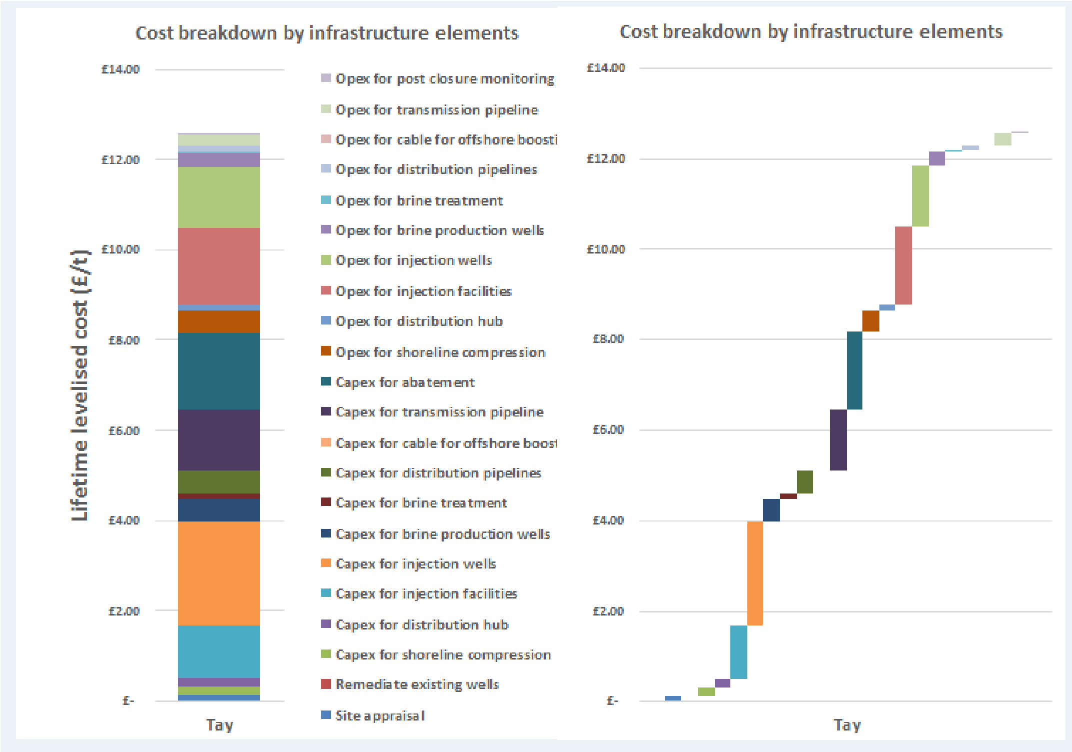
Individual storage unit

Main control page

Detailed cost breakdown of infrastructure elements for user selected storage site

Storage site	Tay
Flow rate (Mt CO2/y)	20
Injection duration (years)	20
Brine production status	Yes
Well type	Vertical
Lowest lifetime levelised cost of storage and transportation (£/t)	£ 12.58
Injection facility type	Subsea

Cost element	**Levelised cost (£/t)**	**Discounted cost (£)**
Site appraisal	£ 0.12	£ 48,738,287
Remediate existing wells	£ -	£ -
Capex for shoreline compression	£ 0.19	£ 74,751,334
Capex for distribution hub	£ 0.20	£ 78,000,000
Capex for injection facilities	£ 1.18	£ 471,900,000
Capex for injection wells	£ 2.29	£ 916,837,170
Capex for brine production wells	£ 0.51	£ 203,741,593
Capex for brine treatment	£ 0.11	£ 44,421,317
Capex for distribution pipelines	£ 0.49	£ 197,906,042
Capex for cable for offshore boosting	£ -	£ -
Capex for transmission pipeline	£ 1.35	£ 540,549,810
Capex for abatement	£ 1.72	£ 689,607,624
Opex for shoreline compression	£ 0.49	£ 196,003,977
Opex for distribution hub	£ 0.12	£ 46,800,000
Opex for injection facilities	£ 1.72	£ 686,400,000
Opex for injection wells	£ 1.36	£ 544,655,744
Opex for brine production wells	£ 0.30	£ 121,034,610
Opex for brine treatment	£ 0.04	£ 17,768,527
Opex for distribution pipelines	£ 0.10	£ 39,581,208
Opex for cable for offshore boosting	£ -	£ -
Opex for transmission pipeline	£ 0.27	£ 107,572,101
Opex for post closure monitoring	£ 0.01	£ 4,202,601
Total	£ 12.58	£ 5,030,471,944


Cost breakdown by infrastructure elements
Lifetime levelised cost (£/t)
£14.00
£12.00
£10.00
£8.00
£6.00
£4.00
£2.00
£-
Tay
Opex for post closure monitoring
Opex for transmission pipeline
Opex for cable for offshore boosti
Opex for distribution pipelines
Opex for brine treatment
Opex for brine production wells
Opex for injection wells
Opex for injection facilities
Opex for distribution hub
Opex for shoreline compression
Capex for abatement
Capex for transmission pipeline
Capex for cable for offshore boost
Capex for distribution pipelines
Capex for brine treatment
Capex for brine production wells
Capex for injection wells
Capex for injection facilities
Capex for distribution hub
Capex for shoreline compression
Remediate existing wells
Site appraisal
Cost breakdown by infrastructure elements
£14.00
£12.00
£10.00
£8.00
£6.00
£4.00
£2.00
£-
Tay

Detailed input sheets

Expert users can also update the detailed input sheets of the models, which include the following:

- Modelling inputs sheet:
    - Definition of terminal names, pipeline size categories, flow rate categories, duration categories and injection facility types.
- Shoreline locations sheet:
    - Shoreline terminal name, latitude and longitude
- Well requirements sheet:
    - Storage Unit Description
    - Flow rate (Mt CO_2/y)
    - Injection duration (years)
    - Brine production status
    - Well type
    - Well conversion status
    - CO_2 injection wells
    - Converted CO_2 injection wells
    - Brine production wells
    - Bottom hole pressure (MPa)
    - Grid length (m)
    - Grid width (m)
    - Average well depth (m)
    - Maximum brine production (m3/d)
- Storage specifications sheet:
    - Storage Unit Description
    - Sink ID
    - Storage Unit Type
    - Risk score
    - Latitude
    - Longitude
    - Capacity (Mt CO_2)
    - Area (m2)
    - Water depth
    - Depth to storage (m)
    - Number of existing wells
- Engineering inputs sheet:
    - Physical constants;
    - Engineering assumptions (i.e. Minimum pipeline pressure, Maximum pipeline pressure, Shoreline supply pressure, Compressor efficiency, Routing factor, Pipeline roughness, Injection well diameter, Pipe utilisation factor, Well utilisation factor, Storage per appraisal well
    - High-level cost assumptions:
        - Fractions for Transportation pre-FID, Injection facility pre-FID, Injection well pre-FID, Contingency, Transportation abatement, Injection facility abatement, and Injection well abatement
        - Post closure monitoring duration
        - Monitoring frequency
    - Infrastructure timing assumptions:
        - Site appraisal (Default is -7 years)
        - Pre FID (Default is -4 years)

        - Construction start (Default is -3 years)
        - Construction end (Default is -1 years)
        - Operation (Default is 0 years)
    - Well spacing assumptions
    - Engineering assumptions for different storage types (i.e. whether seismic, field development, water discharging, oil processing and manned platform are needed)
    - Unit conversion values
- Infrastructure unit cost sheet:
    - CAPEX and OPEX assumptions for wells, injection facilities, hubs, transmission and distribution pipelines, water treatment facilities, appraisal, compressor and power cables
    - CAPEX and OPEX multipliers for manned platforms and subsea injection wells

9 Appendix: Model input tables

Modelling inputs page

Total terminals
10

Total pipeline sizes
20

Total flow rates
7

Shoreline terminal	Pipeline diameter (inches	Flow rate (Mt CO2/y)
Bacton	4.5	2
Barrow	6	5
Easington Shore	8	10
Forth	10	15
Humber	12	20
Milford Haven	14	40
St Fergus	16	60
Teesside	18	
Thames	20	
Wirral	22	
	24	
	26	
	28	
	32	
	36	
	40	
	44	
	48	
	52	
	56	

Total durations
4

Total injection facilities
4

Injection duration (years	Injection facility
10	Subsea
20	Small platform
30	Medium platform
40	Large platform

Shoreline locations page

ID	Shoreline termina	Longitude	Latitude
1	Bacton	1.46	52.86
2	Barrow	-3.18	54.09
3	Easington Shore	0.12	53.65
4	Forth	-3.69	56.01
5	Humber	0.23	53.36
6	Milford Haven	-5.08	51.7
7	St Fergus	-1.84	57.58
8	Teesside	-1.19	54.61
9	Thames	0.69	51.44
10	Wirral	-3.32	53.34

Well requirements page

ID	Description	Flow rate (Mt CO2/y)	Injection duration (years)	Brine production status	Well type	Well conversion status	CO2 injection wells	Converted CO2 injection well	Brine production well	Bottom hole pressure (MPa)	Grid length (m)	Grid width (m)	Average well depth (m)	Maximum brine production (m3/d)
1	Forties 5	2	10	No	Vertical	No	5			39.00	4,000	2,400	2,775	
2	Forties 5	2	20	No	Vertical	No	6			39.00	4,000	3,200	2,775	
3	Forties 5	2	30	No	Vertical	No	7			39.00	4,000	4,800	2,775	
4	Forties 5	2	40	No	Vertical	No	7			39.00	4,000	4,800	2,775	

Storage specifications page

Description	Sink ID	Type	Risk score	Latitude	Longitude	Capacity (Mt CO2)	Area (m2)	Water depth	Depth to storage (m)	Existing wells
Forties 5	372	Saline Aquifer	183	57.51	1.17	350	124,230,000	80	2,336	1840
Bunter_zone4	139	Saline Aquifer	152	54.34	1.64	400	104,760,000	55	1,590	409
Tay	235	Saline Aquifer	182	57.21	0.95	100	21,880,000	110	1,992	390
Firth of Forth	351	Saline Aquifer	169	56.08	3.02	100	2,720,000	85	2,500	25

Engineering inputs page

Physical constant	Value	Unit
Radius of Earth	6,370,000	m
Acceleration due to gravity	9.80	ms-2

Engineering assumptions	Value	Unit
Minimum pipeline pressure	10	MPa
Maximum pipeline pressure	25	MPa
Shoreline supply pressure	10	MPa
Compressor efficiency	75%	
Routing factor	1.20	
Pipeline roughness	4.56E-05	m
Injection well diameter	4.50	inch
Pipe utilisation factor	75%	
Well utilisation factor	90%	
Storage per appraisal well	2,400	Mt CO2

Infrastructure assumptions	Timeline	Unit
Site appraisal	-7	Years
Pre FID	-4	Years
Construction start	-3	Years
Construction end	-1	Years
Operation	0	Years

Transportation pre-FID	0.5%	
Injection facility pre-FID	10%	
Injection well pre-FID	1%	
Contingency	30%	
Transportation abatement	10%	
Injection facility abatement	50%	
Injection well abatement	30%	
Post closure monitoring duration	20	years
Monitoring frequency	5	years

Injection facility	Maximum wells	Average distance of well from centroid to well spacing ratio	Maximum distance of well from centroid to well spacing ratio
Subsea	2	0.5	0.5
Small platform	6	0.9	1.1
Medium platform	12	1.3	1.8
Large platform	20	1.7	2.5

Storage type	Seismic needed	Field development	Water discharging	Oil processing	Manned platform needed
Saline Aquifer	Yes	No	Yes	No	No
Gas Condensate	No	Yes	Yes	No	No
Oil & Gas	No	Yes	No	Yes	Yes
Gas	No	Yes	Yes	No	No

Initial unit	Final unit	Conversion value
Mt	kg	1,000,000,000
Year	second	31,536,000
Inch	metre	0.0254

Infrastructure unit cost page

Compressor capex (£/MW)	Opex (share of capex)	Cost of energy (£/MWh)
£ 3,750,000	4%	£ 52.00

Transmission pipeline length (km)	Capex (£/inch/km)	Opex (share of capex)
1	£ 180,288	1%
25	£ 154,247	1%
30	£ 138,555	1%
40	£ 116,436	1%
50	£ 103,165	1%
60	£ 93,483	1%
80	£ 82,632	1%
100	£ 76,122	1%
150	£ 67,107	1%
200	£ 62,600	1%
250	£ 60,096	1%
300	£ 58,093	1%
400	£ 55,965	1%
500	£ 54,587	1%
600	£ 53,669	1%
700	£ 53,085	1%

Power cable capex (£/km)	Opex (share of capex)
£ 500,000	0%

Seismic appraisal cost (£/km2)	HC field development (£/km2)	Well remediation cost (share of capex)
£ 31,250	£ 17,500	25%

Injection facility type	Maximum water depth (m)	Capex (£)	Opex (share of capex)
Subsea	100	£ 20,000,000	8%
Subsea	150	£ 30,000,000	8%
Subsea	300	£ 40,000,000	8%
Small platform	100	£ 50,000,000	6%
Small platform	150	£ 75,000,000	6%
Small platform	300	£ 100,000,000	6%
Medium platform	100	£ 75,000,000	6%
Medium platform	150	£ 112,500,000	6%
Medium platform	300	£ 150,000,000	6%
Large platform	100	£ 100,000,000	6%
Large platform	150	£ 150,000,000	6%
Large platform	300	£ 200,000,000	6%

Fixed capex (£)	Variable capex (£/m)	Opex (share of capex)
£ 10,000,000	£ 3,600	3%

Maximum water depth (m)	Flow rate (Mt CO2/y)	Fixed capex (£)	Opex (share of capex)
100	0	£ 50,000,000	2%
100	2	£ 55,000,000	2%
100	5	£ 55,829,597	2%
100	10	£ 57,235,247	2%
100	15	£ 58,616,951	2%
100	20	£ 60,000,000	2%
100	40	£ 65,166,272	2%
100	60	£ 70,000,000	2%
150	0	£ 60,000,000	3%
150	2	£ 65,000,000	3%
150	5	£ 65,829,597	3%
150	10	£ 67,235,247	3%
150	15	£ 68,616,951	3%
150	20	£ 70,000,000	3%
150	40	£ 75,166,272	3%
150	60	£ 80,000,000	3%
300	0	£ 65,000,000	3%
300	2	£ 70,000,000	3%
300	5	£ 70,829,597	3%
300	10	£ 72,235,247	3%
300	15	£ 73,616,951	3%
300	20	£ 75,000,000	3%
300	40	£ 80,166,272	3%
300	60	£ 85,000,000	3%

Distribution pipeline length (km)	Capex (£/inch/km)	Opex (share of capex)
0.1	£ 362,847	1%
2	£ 213,542	1%
4	£ 138,889	1%
7	£ 107,019	1%
10	£ 94,184	1%
15	£ 84,259	1%
20	£ 79,297	1%
30	£ 74,306	1%
40	£ 71,832	1%
50	£ 70,347	1%

Injection facility	Manned platform capex multiplier	Manned platform opex multiplier	Injection well capex multiplier
Subsea	1.5	1	1.25
Small platform	1.5	1	1
Medium platform	1.5	1	1
Large platform	1.5	1	1

Water processing fixed capex	Water processing marginal capex	Water processing opex (share of capex)	Oil processing fixed capex	Oil processing marginal capex	Oil processing opex (share of capex)	Unit size brine production (m3/d)
£ 2,800,000	£ 1,200,000	2%	£ 32,200,000	£ 13,800,000	2%	16,400